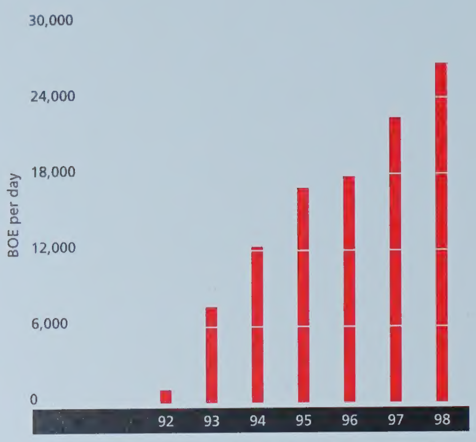
ADHERENCE TO A DISCIPLINED RE-INVESTMENT PROGRAM WAS THE KEY TO SUCCESS IN 1998

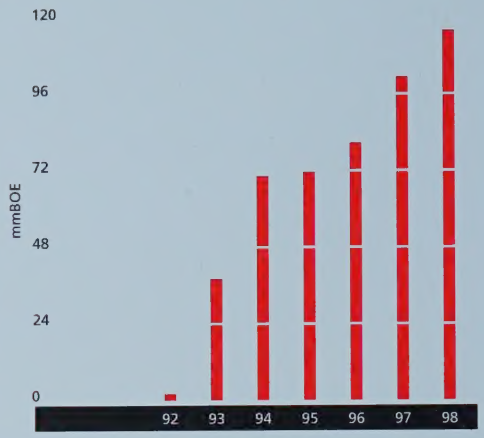
Encal

ENCAL ENERGY LTD.
PERFORMANCE REPORT
1998

#69



Annual production growth



Annual reserves growth

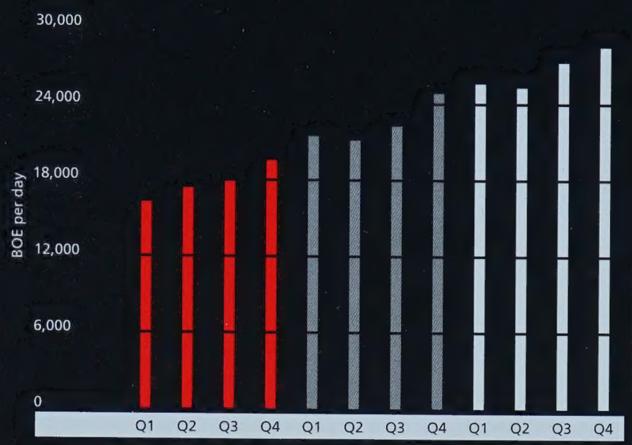
Performance

REGIONAL FOCUS IS KEY TO CONSISTENT, EFFICIENT RESULTS

Encal Energy Ltd. is an intermediate oil and gas exploration and production company, headquartered in Calgary, Alberta, Canada. The Company focuses on natural gas and light oil projects, placing a strong emphasis on efficiently finding and producing reserves.

Encal strives to be a top performer in key industry measures of production growth, finding and development costs and on-stream costs. A Core Program is carried out in the Western Canadian Basin and high impact exploration programs are selectively pursued in under-explored basins in eastern and western Canada.

Encal is publicly traded on
The Toronto Stock Exchange, symbol ENL, and on the
New York Stock Exchange, symbol ECA.



Quarterly production growth
1996 1997 1998

Financial

Continued production growth supported by efficient reserve additions

($ thousands except per share amounts)		1998	1997	%
Financial	Petroleum and Natural Gas Sales	176,463	170,624	3
	Cash Flow From Operations	74,144	84,101	(12)
	Per Common Share - Basic	0.70	0.81	(14)
	- Fully Diluted	0.67	0.77	(13)
	Net Earnings	2,737	13,031	(79)
	Per Common Share - Basic	0.03	0.12	(75)
	- Fully Diluted	0.03	0.12	(75)
	Net Capital Expenditures	163,506	158,154	(3)
	Long Term Debt	223,261	143,414	56
Operating	Production			
	- Crude Oil (bbls/d)	9,313	6,931	34
	- Natural Gas (mcf/d)	143,098	130,197	10
	- Natural Gas Liquids (bbls/d)	3,071	2,485	24
	- Total (BOE/d)	26,694	22,436	19
	Reserves			
	Crude Oil and NGLs (mbbls)			
	- Proven	34,498	28,488	21
	- Proven plus Probable	47,837	40,912	17
	Natural Gas (bcf)			
	- Proven	481	410	17
	- Proven plus Probable	682	605	13

A clear and simple strategy has yielded a strong identity for Encal

Share

1998 proved to be a very important year for Encal. Continued growth in both production and reserves during the year has assisted in differentiating Encal as a consistent and efficient performer. As in prior years, Encal's growth has been generated by its internal exploration and development program which remains focussed on the Company's two core operating areas of west central Alberta and northeastern British Columbia. We have been successful in funding this growth program entirely through internal means since 1993. The best measure of future potential of any company is its past performance and current financial strength. In this regard, Encal has stood out during 1998 and has the potential to be even stronger during 1999.

Consistent and Efficient Growth Since 1995, Encal has geographically focused its efforts in two core areas resulting in a considerable operating advantage. This advantage is measured in our knowledge and experience base, the efficiency of operations due to proximity and the inventory of future opportunities. This clear and simple strategy has yielded a strong identity and focus for our Company.

Within these core areas, Encal has further refined its focus. By specializing in only a handful of geological play types, the Company is able to refine its concepts and establish increasing levels of confidence in the attainment of attractive risk-adjusted financial returns. This concept of "Regional Excellence" has proven to be a very successful strategy in many geological basins with levels of maturity similar to the Western Canadian Sedimentary Basin.

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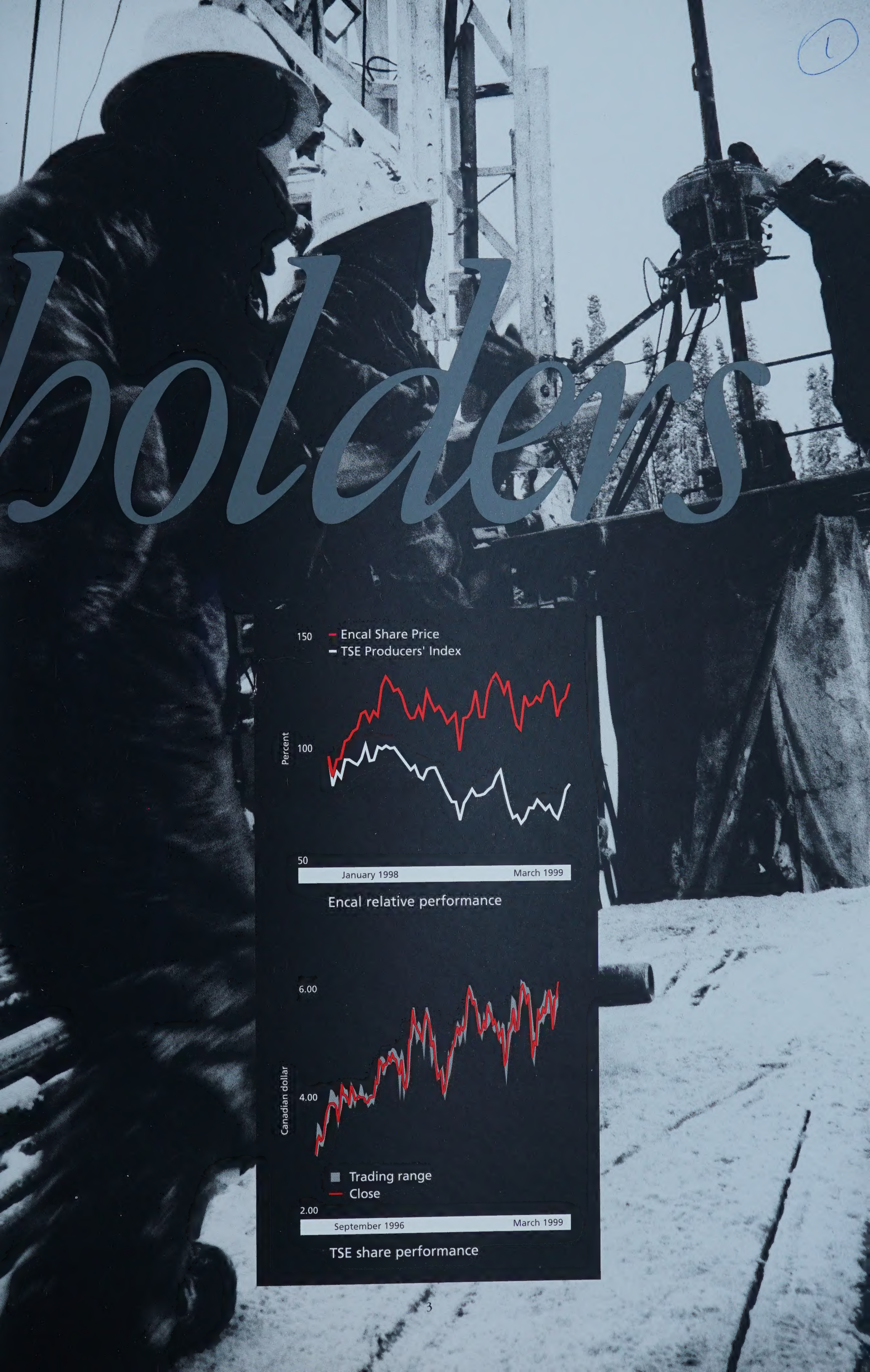


Encal relative performance

TSE share performance

ENCAL'S STRATEGY FOR 1999 REPRESENTS A CONTINUATION OF PRIOR YEARS' APPROACH

Also contributing to Encal's track record of consistency and efficiency is the Company's project selection process, "Portfolio Management". The investment flexibility associated with a variety of risk versus reward opportunities, within the current inventory, provide a significant advantage. This mix provides for a stable growth profile and a predictable cost structure looking forward.

The application of these concepts of Regional Excellence and Portfolio Management have provided Encal with an enviable performance record over the past three years.

A Track Record of Growth

	Pace	Costs
Production		
1998	19%	$14,566/BOE/d
Past three year average	22%	$14,445/BOE/d
Reserves (Proven)		
1998	19%	$7.13/BOE
Past three year average	19%	$7.23/BOE

OUTLOOK: Encal's growth strategy for 1999 is, for the most part, a continuation and refinement of prior years' approach. Our base program in the two core operating districts will see capital expenditures totalling $145 million. An additional five percent is planned for new basin exploration. As in the prior year, all costs associated with the new basin initiative will be paid for by the core programs. For 1999, significant exposure to improving natural gas pricing and a conservative balance sheet, will enable Encal to fund the year's growth plan internally with year-end debt not expected to exceed 2.5 times the trailing cash flow.

David D. Johnson
President and
Chief Executive Officer
March 12, 1999

THE SUCCESS OF ENCAL IS A DIRECT RESULT OF THE EFFORTS OF OUR EMPLOYEES

The 1999 capital program will target natural gas opportunities within current inventory. As a result, the majority of growth will occur in natural gas volumes with liquid production remaining relatively flat over the year.

Crude oil pricing, which is expected to remain low throughout the year, has caused many companies to be under considerable financial pressure. As a result, it may be possible for Encal to enhance its growth plans through acquisition during 1999. However, as in prior years, Encal will remain disciplined in its approach.

RECOGNITION The success of Encal is a direct result of a clear and simple business plan and the efforts of our staff. The continued creativity and diligence demonstrated by Encal's employees, both in the field and office, make the difference. I would like to take this opportunity to thank each employee for their contribution to Encal's performance during the past year. Together we will work to achieve our objectives in 1999.

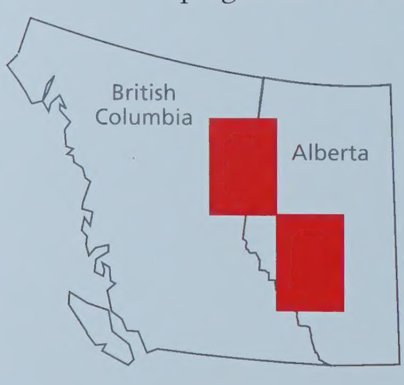
On behalf of the management and staff, I would also like to recognize the excellent guidance and direction provided by Encal's Board of Directors. Throughout the challenging year of 1998, their contribution was evident and greatly appreciated.

Encal's key business objective is to generate sustainable growth of 20 percent per annum within the framework of an efficient and consistent cost structure. To achieve this goal, the Company focuses in selected regions and on specific geologic zones that offer the best potential to deliver meaningful reserve and production additions from natural gas and light oil projects.

Achieving this regional focus is the result of a five-year process. During this time, Encal has refined its approach to concentrate on four key plays within two principal regions in western Canada. Within these regions, the Company has steadily and methodically increased its dominance, efficiency and expertise on the focus plays. The benefits of building this regional excellence include an evolution to higher working interest positions, lower field operating costs and, perhaps most significant, reduced risk on exploration and development decisions.

Encal typically commences a project with a toe-hold position to test new concepts on a modest scale. Frequently, the technical approach will incorporate the application of special technologies that could significantly reduce risk or costs for the particular play. When the idea and application proves successful, the Company moves aggressively to add to its asset base in the immediate area.

The Wilson Creek project is an excellent example of this practice. The progression from a proportionately small project in the portfolio to a major producing area for the Company is described on page 11.

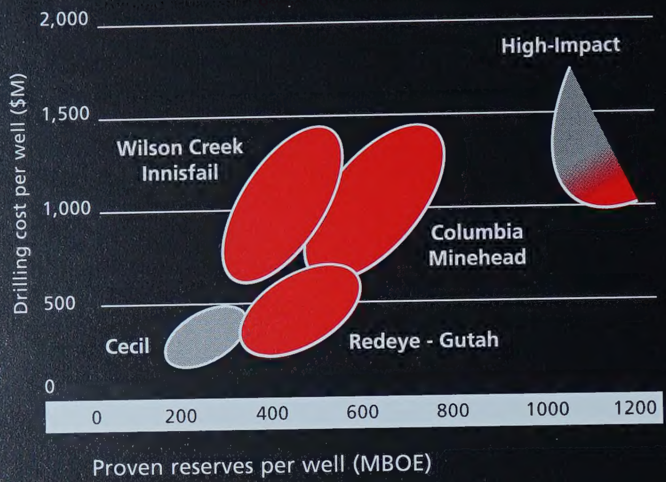


Two regions in western Canada account for 95 percent of Encal's capital budget.

REGIONAL Exc

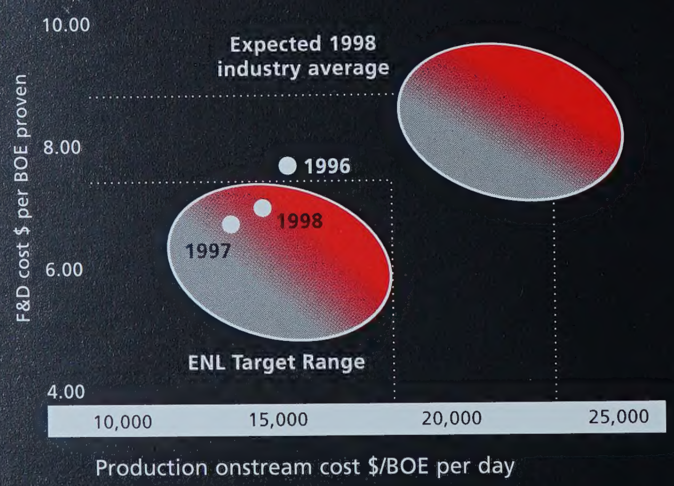

Northeast British Columbia Core Area
Mesozoic Gas & Light Oil
Paleozoic Gas
Redeye
Beatton
Rigel
Ft. St. John
West Central Alberta Core Area
Cretaceous Gas
Mississippian Gas
Cherhill
Modeste
Columbia Minehead
Wilson Creek
Ferrier
Innisfail
ellence
Two Core Areas Four key Projects

Portfolio of Key Projects



- Predominantly natural gas focused
- Four major play types
- Variety of risk versus reward opportunities
- Careful prospect selection yields consistent and efficient results
- Focus on maintaining a range of investment choices

Portfolio Performance Targets



- Finding and development (proven): $7.00 per BOE
- Production on-stream: $17,500 per BOE per day
- Top quartile results relative to industry peers

A complementary project mix provides consistent results

Portf

Efficient production and reserve additions drive cash flow and net asset value gains on a per share basis.

$7.13 PER BOE

Results: All-in finding & development costs (proven): $7.13 per BOE
Production on-stream costs: $14,566 per BOE per day

Through the 1990s, oil and gas exploration success has been increasingly measured in terms of finding and development costs — the dollar cost per unit to establish new or incremental reserves. But an exclusive focus on that single measure tells only part of the story. An equally important consideration is the production on-stream cost — the dollar cost per unit to establish new or incremental production. It is only by consistently finding and producing new volumes efficiently, that companies can record sustainable, profitable growth.

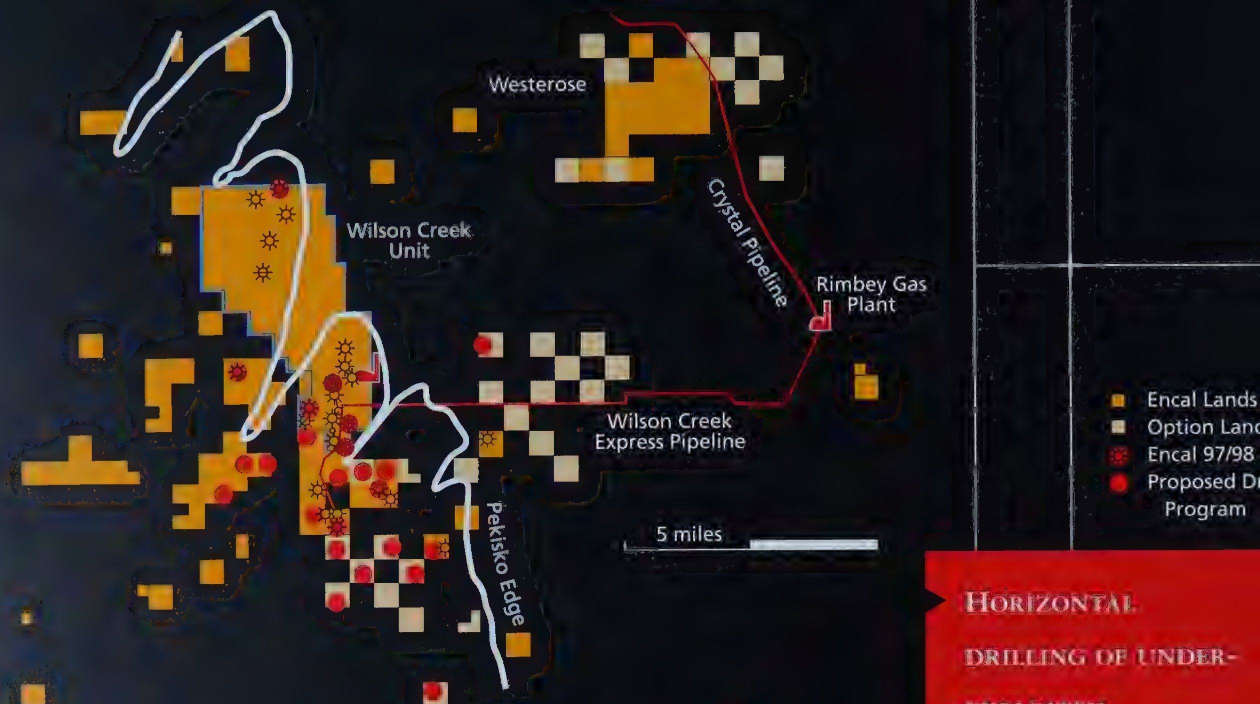
	Capital	Net Production Additions	Production Additions Cost
	($ thousands)	(BOE/d)	($/BOE/d)
1996	109,280	7,146	15,292
1997	158,154	11,420	13,849
1998	163,506	11,225	14,566
Cumulative 1996-1998	430,940	29,791	14,465

Cost of Net Production Additions

olio Management

Wilson Creek

Mississippian Gas Project



Horizontal drilling of under-exploited Mississippian gas reservoirs.

Major regional farm-in covering 111 gross sections.

Innisfail

Mississippian Gas Project

Operating experience gained at Wilson Creek is now being applied at Innisfail.

West Central Alberta Core Area - *Wilson Creek:* The Wilson Creek property has grown from an initial 23 percent working interest position in the original Unit to a dominant growth project in Encal's portfolio. The Unit commenced production in 1968, and achieved a peak production rate of 20 million cubic feet per day in 1988 but had since declined to five million cubic feet per day.

Recognizing the potential for improvement, Encal increased its ownership in the Unit to 48 percent through two acquisitions. At the same time, Encal pursued an active land acquisition and drilling program on lands adjacent to the Unit. In addition Encal's technical evaluation indicated potential production increases through the application of horizontal natural gas drilling. This concept was evaluated with the drilling of two wells in 1997 and an additional pair in early 1998. The impact of the horizontal program resulted in sizeable productivity increases as well as reserve additions. As area deliverability grew, Encal initiated the Wilson Creek Express Pipeline to transport up to 45 million cubic feet per day of new gas volumes to the Rimbey Gas Plant.

In order to capture more benefit from this play, Encal has also secured a large undeveloped land base plus new production and facilities through a combination of property swaps and industry farmins in the Innisfail area. This new project area is expected to be active for several years, with new volume growth commencing during the fourth quarter of 1999.

Northeast British Columbia Core Area - *Rigel:* During 1998, the ongoing exploitation drilling program at Rigel resulted in the full delineation of four high-quality Cecil light oil pools. Encal operates this project and holds an average 80 percent working interest. In 1999, the Company expects to complete the installation of water injection facilities.

Redeye: The Redeye project provides Encal with continued exploration and development drilling opportunities for shallow Cretaceous and Triassic gas targets. In 1998, the Company drilled 11 successful wells resulting in the discovery of four new gas pools and one oil pool. Production from this winter-only access area averaged 16 million cubic feet per day of natural gas sales during the fourth quarter of 1998. The Company holds more than 36,000 net undeveloped acres in the area and plans to drill at least 15 additional wells in 1999.

Rigel

CECIL SAND LIGHT OIL PROJECT

ENCAL'S FLAGSHIP LIGHT OIL PROPERTY, PRODUCING MORE THAN 4,000 BARRELS PER DAY GROSS.

- Proposed Drilling Program
- 26 Oil Producers Drilled in 1997/98
- Natural Gas
- Crude Oil
- Water

Redeye

HALFWAY AND BLUESKY GAS PROJECT

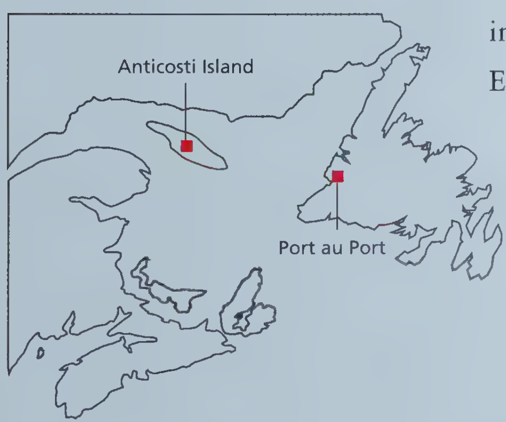
THE REDEYE AREA OFFERS CONTINUED EXPLORATION & DEVELOPMENT DRILLING OPPORTUNITIES.

- Encal Land
- Option Land
- Gas Pool
- Encal 97/98 Well
- Proposed Drilling Program

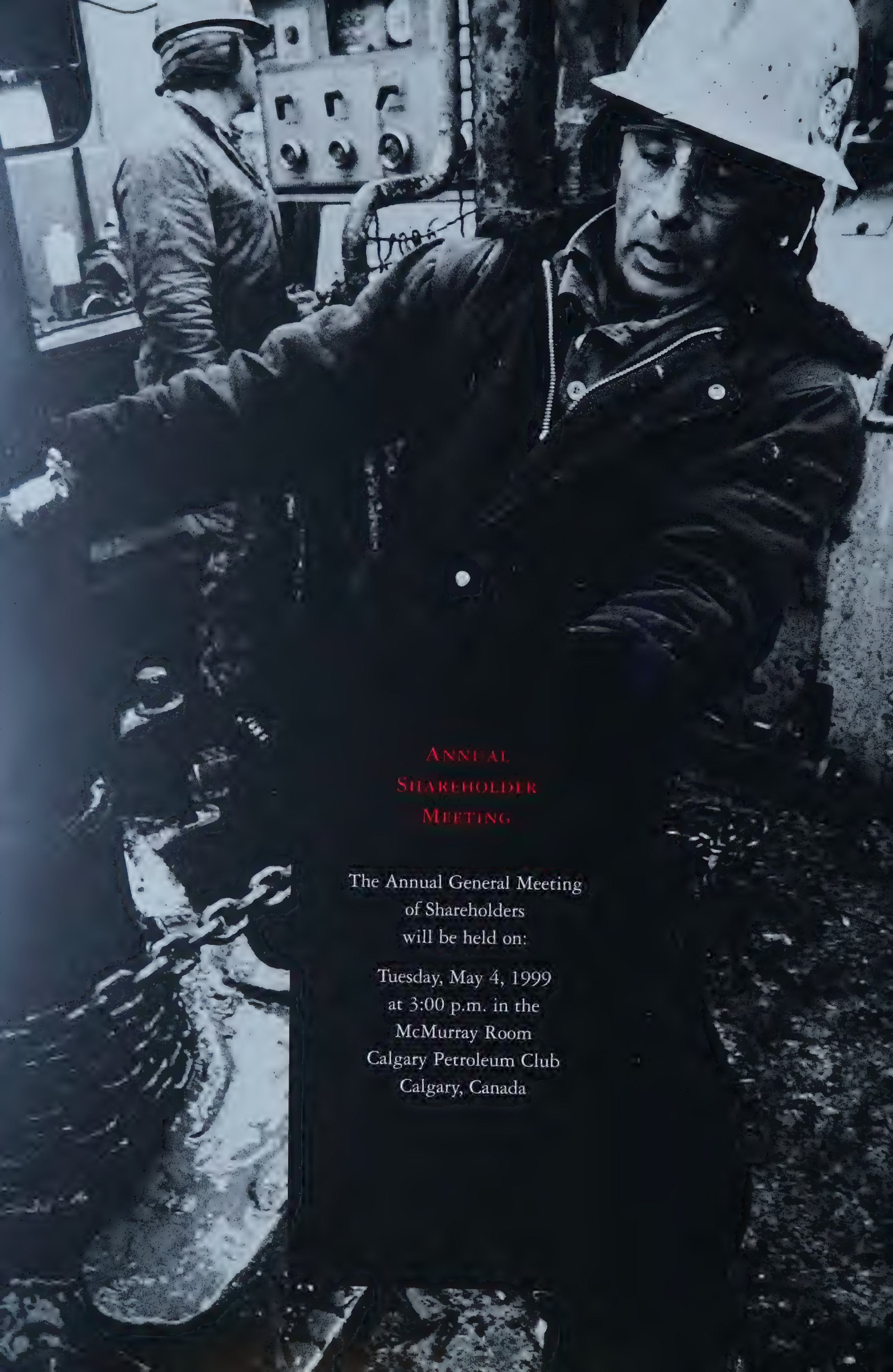
New Basin Exploration Encal devotes a small portion of its annual budget to impact exploration projects in new basins across Canada. The purpose of this impact program is to provide shareholders with a managed exposure to higher reward prospects than the Company typically pursues in its western Canada core operations. Impact projects, when successful, yield a material uplift to the reserves and production base and may ultimately evolve into a new core operating area.

Encal evaluates potential impact projects by carefully applying a strict set of selection criteria. In particular, we concentrate on new basins within Canada that offer reasonable drilling depths and multi-season, onshore access. Since high-impact projects also carry significantly increased risk, we also focus our efforts on projects which offer multiple drilling opportunities, as several exploratory wells may be required before a commercial discovery is made.

During 1998, Encal commenced an impact exploration program in the Anticosti Basin, Gulf of St. Lawrence region, eastern Canada. The Anticosti Basin is a lightly explored Paleozoic basin having an established hydrocarbon source and reservoir system, plus producing analogues throughout the eastern and central United States. The Company has committed to a three-year program, which includes the acquisition of 500 kilometres of new two-dimensional seismic and the drilling of at least five exploratory wells. Although the first two wells of this program, drilled at the Roliff and Jupiter prospects on Anticosti Island, Quebec were dry and abandoned, they did provide valuable new technical information which will be incorporated into Encal's 1999 and 2000 activities. In early 1999, Encal will participate in the third well of the Anticosti Basin program, at Shoal Point on the Port-au-Port Peninsula, western Newfoundland.



New Basin Exploration accounts for approximately five percent of Encal's annual capital.



Annual Shareholder Meeting

The Annual General Meeting
of Shareholders
will be held on:

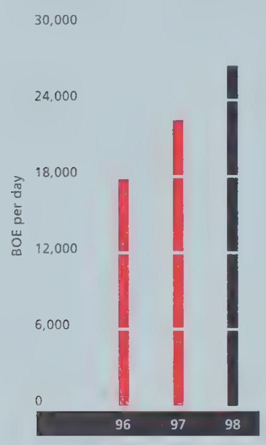
Tuesday, May 4, 1999
at 3:00 p.m. in the
McMurray Room
Calgary Petroleum Club
Calgary, Canada

md&a

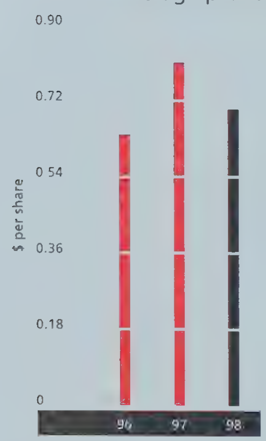
Management's Discussion and Analysis

MANAGEMENT'S DISCUSSION AND ANALYSIS

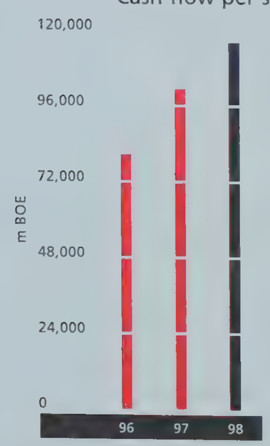
The following discussion and analysis should be read in conjunction with the Financial Statements. Certain comparative figures have been reclassified or restated to conform with the current financial statement presentation.



Average production



Cash flow per share



Reserves
Proven plus probable

1998 OVERVIEW

Encal has a proven record of efficiently adding and producing reserves. The Company's growth has been accomplished through a combination of exploration and development activities and strategic acquisitions. Production in 1998 averaged 26,694 BOE per day compared to 22,436 BOE per day in 1997, an increase of 19 percent. The Company has achieved a three year record of adding 22 percent compounded annual production growth. This growth has been financed by cash flow and debt; Encal has not issued equity in the market since 1993. The Company is well positioned to achieve strong results in 1999 and into the future.

As a result of lower crude oil and natural gas liquids pricing, higher hedging and financing charges, cash flow from operations was $74.1 million in 1998, a 12 percent decrease from the 1997 level of $84.1 million. Correspondingly, cash flow from operations per share decreased 14 percent in 1998 from $0.81 per share in 1997 to $0.70 per share. The Company's combined average crude oil and NGL price per barrel averaged $15.82 per barrel in 1998, reduced from $23.52 per barrel in 1997. Foreign exchange hedging charges were $10.3 million in 1998.

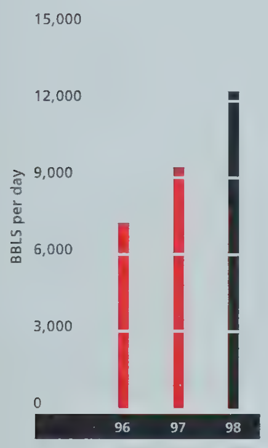
The Company has significantly reduced its foreign exchange hedging position in 1999. As of December 31, 1998 two fixed rate foreign exchange transactions are in place with a fair value of $200,000.

Encal's net capital spending increased from $158.2 million in 1997 to $163.5 million in 1998. Proven plus probable finding and development costs in 1998 increased to $6.71 per BOE from $5.48 per BOE in 1997. Proven finding and development costs also increased to $7.13 per BOE in 1998 compared to $6.95 per BOE in 1997. Finding costs include eastern Canada high impact capital expenditures of $7.1 million plus the net impact of acquisition and disposition activity and technical revisions.

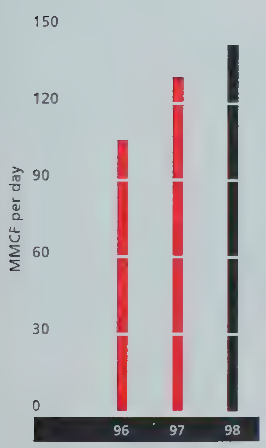
For the purposes of calculating unit costs, natural gas is converted to a barrel equivalent using 10 thousand cubic feet equal to one barrel unless otherwise stated.

Production

Crude oil sales volumes increased 34 percent to 9,313 barrels per day in 1998 compared to 6,931 barrels per day in 1997. Increases in oil production are attributable to successful exploration and development activity at the Rigel and Oak properties in British Columbia and Westerose, Alberta. Encal recorded its strongest growth in the fourth quarter of the year increasing average quarterly production by 744 barrels per day. Oil production averaged 10,016 barrels per day in the fourth quarter of 1998; a 22 percent increase from the fourth quarter 1997 rate of 8,180 barrels per day.



Crude oil & NGL production



Natural gas production

Natural gas sales volumes increased 10 percent in 1998 to average 143.1 million cubic feet per day compared to 130.2 million cubic feet per day in 1997. Increases in natural gas production are attributable to successful exploration and development activity at the Redeye, Cherhill, Crystal and Wilson Creek properties. Natural gas sales volumes increased to average 150.4 million cubic feet per day in the fourth quarter of 1998 compared to 138.0 million cubic feet per day in the fourth quarter of 1997.

Natural gas liquids sales volumes increased 24 percent to 3,071 barrels per day in 1998 compared to 2,485 barrels per day in 1997. The increased production is attributable to liquid rich natural gas properties at Redeye, Columbia/Minehead and Cherhill. Natural gas liquids production averaged 3,447 barrels per day during the fourth quarter of 1998; an increase of 20 percent over the fourth quarter 1997 production of 2,877 barrels per day.

Production Summary

	Fourth Quarter				
	1998	1997	1998	1997	1996
Crude Oil (bbls/d)	10,016	8,180	9,313	6,931	5,432
Natural Gas (mmcf/d)	150.4	138.0	143.1	130.2	105.7
NGL (bbls/d)	3,447	2,877	3,071	2,485	1,800
Production (BOE/d)	28,506	24,855	26,694	22,436	17,803
Annual Production (mBOE)			9,743	8,189	6,480

Production Reconciliation

	Natural Gas	Crude Oil and NGL	Equivalent Production
	(mmcf/d)	(bbls/d)	(BOE/d)
Production Fourth Quarter 1997	138.0	11,057	24,855
Decline on Base Production	(30.4)	(2,375)	(5,415)
Production Additions During 1998	48.9	5,785	10,680
Decline on New 1998 Production	(10.4)	(1,119)	(2,159)
Acquisitions	17.0	765	2,465
Dispositions	(12.7)	(650)	(1,920)
Production Fourth Quarter 1998	150.4	13,463	28,506

OIL & GAS MARKETING

The environment in which Encal markets its products is constantly changing. Encal recognizes that a successful marketing strategy must be flexible to react to changing market conditions. Proactive initiatives are necessary to capitalize on opportunities. The market fundamentals for each of the products produced by Encal under went significant changes during 1998.

Crude Oil Sales

Encal's average field price reflects the posted price less deductions for transportation and adjustments for Encal's quality relative to the posted price. As shown by the accompanying pie chart, 54 percent of Encal's crude oil production is light, 42 percent is medium and four percent is heavy. Encal's average field price in 1998 was $16.43 per barrel, down from 1997's price of $24.25 per barrel.

Since peaking at US$25.18 per barrel in January 1997, WTI crude oil prices have been on a continuous decline, averaging US$14.43 per barrel in 1998.

Crude oil production mix

In the past year, more than 100,000 barrels per day of Canadian oil production was shut-in by producers due to uneconomic price levels. Most of the crude oil shut-in has been heavy oil quality. This reduction in western Canadian supply has resulted in a reduced risk of pipeline curtailments which previously had caused delivery disruptions. With strengthened delivery assurance, Encal has been able to optimize its crude oil pricing arrangements. Encal actively seeks to fix premiums over the refiners' posted prices in exchange for short to medium term supply commitments. Although the underlying posted price may fluctuate with market conditions, this strategy ensures that Encal always receives market premium for its crude oil. This strategy has been successful in British Columbia where 100 percent of Encal's light oil production is sold at a premium to postings under term arrangements. Encal currently has similar arrangements in place for light sweet oil production delivering into Edmonton, Alberta as well as medium-sour and heavy production delivering into Hardisty, Alberta.

Crude Oil Pricing

($/bbl)	1998	1997	1996
WTI (US$/bbl at Cushing, Oklahoma)	14.43	20.61	22.01
Average Exchange Rate	1.4835	1.3845	1.3635
WTI (CDN$/bbl at Cushing, Oklahoma)	21.41	28.53	30.01
Less: Transportation Differential Cushing, Oklahoma to Edmonton	(1.32)	(0.89)	(0.78)
Edmonton Light Sweet Posting (CDN$/bbl)	20.09	27.64	29.23
Less: Transportation to Edmonton	(0.56)	(0.37)	(0.43)
Less: Quality Adjustment	(3.10)	(3.02)	(2.33)
Encal Average Field Price	16.43	24.25	26.47

Natural Gas Sales

Canadian natural gas competes in a continental North American market with exports of Canadian natural gas into the U.S. continuing to grow each year. In the past, Canadian exports have been constrained by available pipeline capacity. However, this has been rectified with the 1998 expansion of the Northern Border and TransCanada Pipelines and the regulatory approval of the new Alliance Pipeline scheduled to be in service in 2000. Historically, constrained pipeline capacity caused Canadian natural gas to trade at significant discounts to the price received in export markets. Pipeline capacity will now outstrip western Canadian production capabilities for the foreseeable future. Encal expects demand for western Canadian gas to exceed supply and therefore, the basis differential between export markets will significantly narrow, thus improving the netbacks for gas sold within the province. With this change in pricing paradigms, Encal has systematically reduced its exposure to U.S. based market prices shifting exposure to AECO/NIT market centre in Alberta which will increase to 68 percent in 1999 from 34 percent in 1998.

Since approximately 32 percent of Encal's natural gas production is in British Columbia, the construction of the Alliance Pipeline will provide an alternate export market for British Columbia gas production and Encal expects to capitalize on this incremental demand.

U.S. natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta and British Columbia prices are referenced off AECO/NIT delivery point and Sumas, Washington, respectively. Encal's average price for natural gas increased seven percent to $2.01 per thousand cubic feet in 1998 compared to $1.88 per thousand cubic feet in 1997.

Alberta Natural Gas Prices

	1998	1997	1996
NYMEX (US$/mmbtu at Henry Hub Louisiana)	2.14	2.63	2.55
Less: Differential (AECO Hub US$/mmbtu)	(0.78)	(1.27)	(1.53)
	1.36	1.36	1.02
Average Exchange Rate	1.4835	1.3845	1.3635
Alberta Price @ AECO (CDN$/mcf)	2.02	1.88	1.39
Less: NOVA Receipt Transportation	(0.13)	(0.13)	(0.12)
Encal Contract/Marketing Premium	0.16	0.24	0.43
Encal Average Alberta Plantgate Price	2.05	1.99	1.70

British Columbia Natural Gas Prices

	1998	1997	1996
NYMEX (US$/mmbtu at Henry Hub Louisiana)	2.14	2.63	2.55
Less: Differential (Sumas US$/mmbtu)	(0.54)	(0.93)	(1.22)
	1.60	1.70	1.33
Average Exchange Rate	1.4835	1.3845	1.3635
British Columbia Price @ Sumas (CDN$/mcf)	2.37	2.35	1.81
Less: Westcoast Transportation	(0.40)	(0.38)	(0.35)
Encal Contract/Marketing Premium (Discount)	0.11	(0.02)	(0.16)
Encal Average British Columbia Plantgate Price Realization	2.08	1.95	1.30
Less: Westcoast Gathering and Processing *	(0.38)	(0.36)	(0.33)
Encal Average British Columbia Wellhead Price Realization (CDN$/mcf)	1.70	1.59	0.97

* *British Columbia has an infrastructure built by Westcoast Energy Inc. that enables gas producers in that province to avoid facility construction in exchange for regulated gathering, processing and transmission fees.*

Natural Gas Liquids Sales

Natural gas liquids make up approximately 25 percent of Encal's total liquids production. Natural gas liquids are sold based upon an Edmonton posted price, less transportation costs and a deduction to fractionate and stabilize the natural gas liquids into their by-product components of propane, butane and condensate. Natural gas liquids prices have been adversely affected by the Asian economic problems. Asian demand for petrochemicals, one of the main users of natural gas liquids, declined significantly. Propane prices at Edmonton averaged $10.94 per barrel in 1998, down from $18.58 per barrel in 1997. Butane prices have similarly declined in 1998 to $12.09 per barrel from $19.08 per barrel in 1997. Average condensate postings at Edmonton were $21.77 per barrel in 1998 versus $30.81 per barrel in 1997.

Risk Management

Crude Oil & Natural Gas

In 1998, Encal used financial instruments to fix approximately 10.6 percent of crude oil and condensate sales at an average WTI price of CDN $20.48 per barrel. This resulted in a crude oil hedging gain of $3.5 million.

As of December 31, 1998, the Company had no crude oil or natural gas financial instruments in place.

Encal has however, fixed the prices on approximately 36 mmcf/d of 1999 natural gas sales through the use of physical sales contracts at an average plant gate price of $2.46 per mcf.

Foreign Exchange

In 1998, Encal used financial instruments to fix approximately $130.0 million of the foreign exchange exposure. With the fall in the Canadian dollar this resulted in a $10.3 million loss. These transactions expired at December 31, 1998. The Company has entered into two financial instruments to fix the CDN/US dollar exchange rate on US$24.0 million for calendar 1999. One structure is an average forward rate swap at $1.5416, and the second is a costless collar with a range between $1.4500 and $1.6000.

Natural Gas Production and Prices by Province

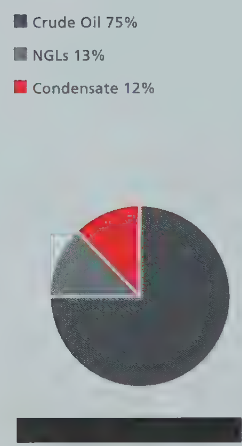
	1998		1997		1996	
	mmcf/d	$/mcf	mmcf/d	$/mcf	mmcf/d	$/mcf
Alberta	97.7	2.05	95.6	1.99	92.4	1.70
British Columbia	45.4	1.70*	34.6	1.59*	13.3	0.97*
Total production and average sales price	143.1	2.01	130.2	1.88	105.7	1.62

* *See British Columbia Natural Gas Prices on page 19.*

Risk Management

($ thousands)	1998	1997	1996
Crude Oil Hedging (Gains) Charges	(3,467)	1,245	4,732
Crude Oil Foreign Exchange Hedging Charges	6,657	965	27
Natural Gas Foreign Exchange Hedging Charges	3,677	568	57
Total Hedging Charges	6,867	2,778	4,816

Natural gas price index portfolio



Liquids production

REVENUE

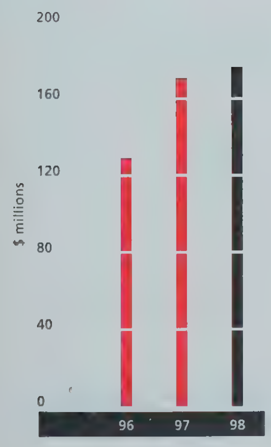
Petroleum and natural gas revenues increased three percent to \$176.5 million in 1998 from \$170.6 million in 1997. The increase in revenues was the result of a 34 percent increase in oil production and a 10 percent increase in natural gas production from the previous year. Increased natural gas prices were more than offset by lower crude oil and natural gas liquids prices.

Revenue

(\$ thousands)	1998	1997	1996
Crude Oil	55,831	61,366	52,623
Natural Gas	104,961	89,215	62,291
Natural Gas Liquids	15,671	19,453	13,655
Other Revenue	–	590	541
Total	176,463	170,624	129,110

Revenue Impact

(\$ thousands)	Crude Oil	Natural Gas	NGL	Total
1996 Revenue	52,623	62,291	13,655	128,569
Increase (Decrease) due to Price	(4,420)	10,353	479	6,412
Increase due to Volume	6,428	10,788	5,104	22,320
Increase due to Acquisitions	9,852	9,850	215	19,917
Decrease due to Dispositions	(3,117)	(4,067)	–	(7,184)
1997 Revenue	61,366	89,215	19,453	170,034
Increase (Decrease) due to Price	(19,783)	6,178	(6,775)	(20,380)
Increase due to Volume	15,182	11,456	2,010	28,648
Increase due to Acquisitions	1,199	6,533	1,732	9,464
Decrease due to Dispositions	(2,133)	(8,421)	(749)	(11,303)
1998 Revenue	55,831	104,961	15,671	176,463



Revenue

EXPENSES

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. The Company's average royalty rate was 16.6 percent in 1998 compared to 18.5 percent in 1997.

The royalty rate for crude oil and natural gas liquids fell slightly from 20.6 percent in 1997 to 20.2 percent in 1998 as a result of lower prices. This was offset by increased royalty rates due to higher productivity wells and the conclusion of royalty holidays on several wells in British Columbia. Unlike Alberta, where oil royalty rates are price and volume sensitive, oil royalty rates in British Columbia are only volume sensitive.

Natural gas royalty rates were reduced from 16.7 percent in 1997 to 14.1 percent in 1998. The decrease was primarily attributable to a corporate comprehensive royalty review, deep gas royalty holidays on several wells in the Columbia area of Alberta and a four percent decrease in the Alberta gas par price. Encal's review led to a reduction in royalties due to amended custom processing submissions, accelerated capital cost allowance recoveries and retroactive British Columbia cost of service recoveries. The Company pays natural gas royalties in Alberta based on the Alberta government published reference price which decreased in 1998 by $0.03 per thousand cubic feet where as the Alberta price realized by Encal increased by $0.06 per thousand cubic feet to $2.05 per thousand cubic feet. The Company's average royalty rate for 1999 is expected to increase to approximately 17.5 percent.

Royalties

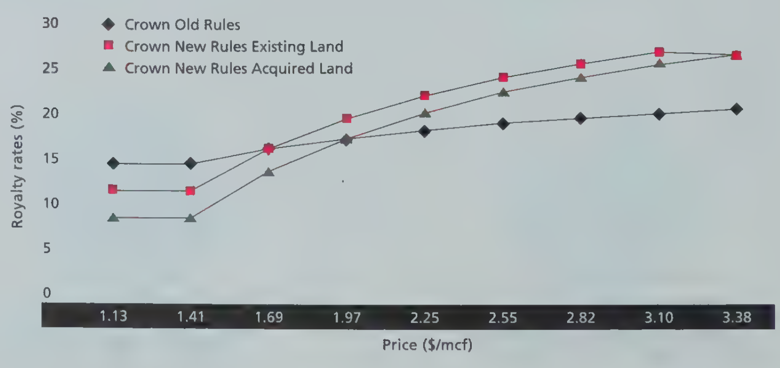
($ thousands)	1998	1997	1996
Royalties			
Crown (net of ARTC)	25,182	25,797	13,439
Freehold and Other	4,087	5,778	5,424
Net Royalties	29,269	31,575	18,863
Total $/BOE	3.00	3.86	2.91
Average Royalty Rate (%)	16.6	18.5	14.6
Crude Oil and NGL			
Royalties	14,439	16,658	11,583
Average Royalty Rate (%)	20.2	20.6	17.5
Natural Gas			
Royalties	14,830	14,917	7,280
Average Royalty Rate (%)	14.1	16.7	11.7

On May 19, 1998, the British Columbia government announced a new cooperative initiative with the oil and gas industry effective June 1, 1998. The initiative provides royalty reductions, work on long term agreements with First Nations and creates a single window regulatory agency. These changes are expected to improve operating netbacks and exploration-production cycle time.

Oil royalty rates in British Columbia have been reduced by approximately 20 percent for wells drilled or recompleted after May 31, 1998.

Natural gas wells drilled or recompleted on existing lands after May 31, 1998 are subject to a reduced base royalty rate of 12 percent (previously 15 percent) whereas new lands acquired after May 31, 1998 are subject to a nine percent minimum royalty rate. Under both scenarios the maximum royalty rate is 27 percent (previously 21 percent) which results when natural gas prices reach $3.38 per mcf.

British Columbia Non-Conservation Natural Gas Royalty Rates



Production

Production expenses for the year increased to $41.9 million from $35.1 million in 1997, a 19 percent increase which corresponds with the 19 percent increase in 1998 production compared to 1997. Production expenses per barrel of oil equivalent were $4.30 per barrel in 1998 compared to $4.28 per barrel in 1997. Per unit production expenses for 1999 are expected to remain consistent with 1998.

Production Expenses

($ thousands)	1998	1997	1996
Total Production Expenses	**41,910**	35,052	27,937
$/BOE	4.30	4.28	4.31
Crude Oil and NGL			
Production Expenses	**18,404**	14,121	11,882
$/BOE	**4.07**	4.11	4.51
Natural Gas			
Production Expenses	**23,506**	20,931	16,055
$/BOE	4.50	4.40	4.17

Operating Netbacks

	Crude Oil and NGL ($/bbl)			Natural Gas ($/mcf)		
	1998	1997	1996	1998	1997	1996
Price	**15.82**	23.52	25.18	**2.01**	1.88	1.62
Royalties, before ARTC	**(3.19)**	(4.85)	(4.40)	**(0.28)**	(0.31)	(0.19)
Production Expenses	**(4.07)**	(4.11)	(4.51)	**(0.45)**	(0.44)	(0.42)
Operating Netbacks	**8.56**	14.56	16.27	**1.28**	1.13	1.01

General and Administrative

General and administrative expense increased 15 percent to $10.2 million in 1998 from $8.8 million in 1997. Correspondingly, production increased 19 percent resulting in a three percent decrease in general and administrative expense per BOE in 1998 to $1.04 from $1.07 in 1997. General and administrative expenses per BOE in 1999 are anticipated to remain consistent with 1998.

Financing Charges

Long term debt increased $79.8 million in 1998 to $223.3 million. Long term debt consists of bank debt and senior notes payable. Financing charges increased during 1998 to $13.4 million from $7.4 million in 1997. The increase in 1998 financing charges was largely a result of higher debt levels during 1998 compared to 1997. Financing charges are anticipated to increase in 1999 due to higher average debt levels.

As at December 31, 1998 the Company has locked in interest rates on $40.0 million of its bank debt; $20.0 million at 5.395 percent covering the period January 1998 to March 1999; and $20.0 million at 6.185 percent covering the period January to December, 1999. Encal's US$50 million senior notes bear interest at 7.61 percent while the interest rate on the Company's bank debt bears interest at the lender's prime rate or at banker's acceptance rate plus a stamping fee.

General and Administrative

($ thousands)	1998	1997	1996
General and Administrative	14,169	12,358	10,567
Recoveries	(4,016)	(3,564)	(2,357)
Net General and Administrative	10,153	8,794	8,210
Net General and Administrative - ($/BOE)	1.04	1.07	1.27
Recoveries of General and Administrative (%)	28	29	22
Number of Employees and Full Time Consultants (at year end)			
Head Office	139	116	102
Field	23	28	19
Total	162	144	121

Financing Charges

($ thousands)	1998	1997	1996
Interest on Bank Debt	6,787	4,416	2,232
Interest on US Senior Notes	5,707	2,565	–
Amortization of Deferred Foreign Exchange Losses	732	94	–
Other	136	294	90
Financing Charges	13,362	7,369	2,322
$/BOE	1.37	0.90	0.36
EBIT			
EBIT	20,064	35,025	23,157
Financing Charges	13,362	7,369	2,322
EBIT Interest Coverage	1.50	4.75	9.97
EBITDA			
EBITDA	88,264	92,425	69,284
Financing Charges	13,362	7,369	2,322
EBITDA Interest Coverage	6.61	12.54	29.84

Definitions
EBIT - earnings before income taxes and financing charges
EBITDA - earnings before income taxes, depletion and depreciation and financing charges

Depletion and Depreciation and Site Restoration and Reclamation

Depletion per BOE in 1998 decreased from $7.01 per BOE in 1997 to $7.00 per BOE. The 1998 depletion and depreciation provision increased 19 percent to $68.2 million compared to $57.4 million in 1997 due to increased production.

The Company provided $2.1 million for site restoration and reclamation in 1998 compared to $2.3 million in 1997. This charge amounts to $0.22 per BOE in 1998 and $0.28 per BOE in 1997. In 1998, $0.09 per BOE was incurred and $0.13 was provided for future site restoration charges. Actual site restoration costs incurred during 1998 and 1997 amounted to approximately $1.0 million in each year.

For purposes of calculating oil equivalence in the depletion calculation, natural gas is converted to a barrel equivalent using six thousand cubic feet equal to one barrel. This conversion factor approximates the relative energy value. The more commonly used financial conversion of 10:1 remains the standard for the Canadian oil and gas industry. This conversion factor historically reflected relative market values of crude oil and natural gas.

Depletion and Depreciation and Site Restoration and Reclamation

($ thousands)		1998	1997	1996
Depletion and Depreciation		66,131	55,144	43,951
Site Restoration and Reclamation		2,069	2,256	2,176
Total		68,200	57,400	46,127
$/BOE	- (Gas to Oil - 10:1)	7.00	7.01	7.12
	- (Gas to Oil - 6:1)	5.16	5.05	5.10
Depletion Rate (%)	- (Gas to Oil - 10:1)	10.46	10.40	10.55
	- (Gas to Oil - 6:1)	10.27	10.40	10.36

Taxes

The Company's effective tax rate decreased in 1998 to 36.9 percent from 49.2 percent in 1997. This rate decrease was the result of Alberta Attributed Canadian Royalty Income and Resource Allowance deductions which were in excess of non-deductible Crown charges. The Company's effective tax rate for 1999 is expected to approximate the Company's corporate income tax rate of 45 percent.

As recommended by The Canadian Institute of Chartered Accountants, effective January 1, 1998, the Company adopted the liability method of tax allocation in accounting for income taxes on a retroactive basis from January 1, 1995. Future income tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities. They are measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Prior to the adoption of the new recommendations, income tax expense was determined using the deferral method of tax allocation. Future tax expense was based on items of income and expense that were reported in different years in the financial statements and tax returns and measured at the rate in effect in the year the differences originated.

The impact of this change is described in Note 1, Future Income Taxes in the Financial Statements.

Encal has $423 million in resource tax pools available to reduce future taxable income (for more details refer to Note 8, Future Income Taxes in the Financial Statements). Current income taxes are not expected to be payable for several years due to the Company's large resource pool balances.

Taxes

($ thousands)	1998	1997	1996
Future Income Taxes	**2,475**	13,600	8,550
Capital Taxes	**1,490**	1,025	767
Total	**3,965**	14,625	9,317
Effective Tax Rate Calculation			
Earnings before Taxes	**6,702**	27,656	20,835
Future Income Taxes	**2,475**	13,600	8,550
Effective Tax Rate (%)	**36.9**	49.2	41.0

Netback Analysis

Net earnings decreased to $0.28 per BOE in 1998, an 82 percent decrease from 1997 of $1.59 per BOE. This decrease is attributable to lower crude oil and natural gas liquids pricing, higher hedging and financing charges.

Netback Analysis

($/BOE)	1998	1997	1996
Petroleum and Natural Gas Sales	**18.11**	20.84	19.92
Hedging Charges	**(0.71)**	(0.34)	(0.74)
Royalties	**(3.00)**	(3.86)	(2.91)
Production Expenses	**(4.30)**	(4.28)	(4.31)
General and Administrative Expenses	**(1.04)**	(1.07)	(1.26)
Financing Charges	**(1.30)**	(0.89)	(0.36)
Capital Taxes	**(0.15)**	(0.13)	(0.12)
Cash Flow from Operations	**7.61**	10.27	10.22
Depletion and Depreciation	**(7.00)**	(7.01)	(7.12)
Future Income Taxes	**(0.25)**	(1.66)	(1.32)
Amortization of Deferred Foreign Exchange Losses	**(0.08)**	(0.01)	–
Net Earnings	**0.28**	1.59	1.78

CAPITAL EXPENDITURES

Net capital expenditures in 1998 increased to $163.5 million from $158.2 million in 1997. These expenditures were concentrated in the Company's core regions of British Columbia and west central Alberta. During 1998 the Company acquired properties for a cost of $64.5 million and sold $49.1 million in properties for net acquisition and disposition expenditures of $15.4 million. During 1998 the Company spent $7.1 million on new basin projects on Anticosti Island, Quebec, and Shoal Point, Newfoundland. These costs consist of $4.3 million of drilling and $2.8 million of seismic expenditures.

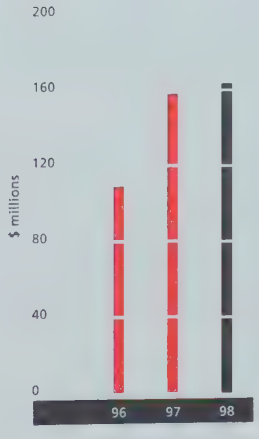
The major capital transaction of 1998 was a swap of non-operated natural gas producing interests at Wapiti and Cutbank and operated production at Marten Hills, Alberta for operated natural gas producing interests in the Innisfail, Markerville and Tindastoll regions of west central Alberta. The Company also acquired an operated 80 percent working interest in the Markerville compression facilities, all associated infrastructure and 6,200 net acres of undeveloped land. The acquired assets, valued at $42.0 million were equal in value and production to the disposed assets. A number of smaller transactions account for the balance of the acquisition effort that was aimed at increasing core area dominance in British Columbia and west central Alberta. Non-core area property disposition activity was accomplished through the sale of numerous properties in 22 separate transactions.

Encal continues to be committed to consolidating its oil and natural gas properties. Encal has focused on divesting non-strategic or marginal assets and acquiring producing properties complementing its existing core regions of British Columbia and west central Alberta. During the last four years Encal has divested of $122.2 million of non-core properties and acquired $153.6 million of complementary properties. This non-strategic asset disposition and core area acquisition program is an ongoing process and will continue in 1999.

Capital Expenditures Summary

($ thousands)	1998	1997	1996
Land and Lease	9,765	18,013	20,581
Seismic	4,228	8,880	7,339
Eastern Canada	7,075	–	–
Drilling and Completions	75,941	72,996	41,129
Property Acquisitions	64,454	57,066	24,645
Property Dispositions	(49,069)	(40,161)	(12,343)
Total Finding Expenditures	112,394	116,794	81,351
Facilities	49,073	39,875	27,210
Corporate Assets *	2,039	1,485	719
Total Finding and Development Expenditures	163,506	158,154	109,280

** Corporate assets include office improvements, equipment, computer hardware and software.*



Capital expenditures

Drilling Results

The Company drilled a total of 138 wells (82.3 net) during 1998 for an overall success rate of 78 percent (71 percent net).

Encal maintained a consistent success rate in 1998 generating production growth and reserve replacement that met corporate targets. A total of 138 gross (82.3 net) wells were drilled and resulted in 62 (32.0 net) natural gas wells, 45 (26.1 net) crude oil wells with 31 (24.2 net) attempts dry and abandoned. The program required $80.3 million which was 10 percent more than the $73.0 million spent in 1997. The 1998 drilling program included a small portion of spending to add a high impact program to the portfolio and it is this component that covers most of the difference between 1997 and 1998 drilling capital. The core program drilling expenditure was virtually the same from 1997 to 1998, yet fewer wells were drilled. Two factors influenced drilling costs: drill rig rates were at a peak through the first quarter of 1998 and Encal's drilling program included more horizontal wells than in 1997.

Exploration and Development Activity Highlights

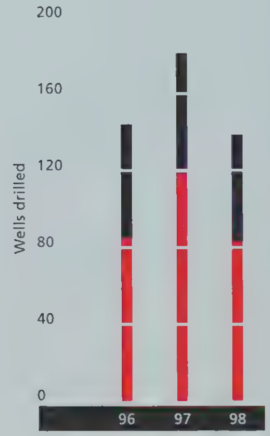
Successful exploration efforts resulted in new gas pool discoveries at Redeye and Gutah, British Columbia plus Open Creek and O'Chiese, Alberta. Much of the development activity focus occurred at Rigel, British Columbia, and at Columbia, Westerose and Wilson Creek, Alberta. Successful horizontal drilling efforts through 1997 led to an expanded horizontal program in 1998, particularly useful to produce under exploited Mississippian gas reservoirs in west central Alberta.

Drilling Results

	1998		1997		1996	
	Gross	Net	Gross	Net	Gross	Net
Natural Gas	62	32.0	66	39.9	54	33.3
Crude Oil	45	26.1	75	47.3	49	24.9
Dry and Abandoned	31	24.2	40	31.2	40	25.5
Total	138	82.3	181	118.4	143	83.7
Success Rate (%)	78	71	78	74	72	70

Drilling Activity

	1998		1997		1996	
	Gross	Net	Gross	Net	Gross	Net
Province						
British Columbia	55	40.2	58	41.9	26	19.1
Alberta	81	41.1	122	75.5	115	62.6
Saskatchewan	–	–	1	1.0	2	2.0
Quebec	2	1.0	–	–	–	–
Total	138	82.3	181	118.4	143	83.7



Drilling activity

Land

Total Canadian undeveloped net acres increased by 19 percent in 1998 to 858,761 net acres from 719,470 net acres in 1997. This increase is attributable to the addition of 181,618 net acres in the province of Quebec. Encal's average working interest in undeveloped acreage located in western Canada increased to 69 percent in 1998 from 64 percent in 1997. In 1998, Encal invested $7.4 million on undeveloped land, participating selectively at land sales through the year with acquisitions in defined core regions at an average working interest of over 97 percent.

Encal acquired over 77,000 net acres through Crown and freehold purchases in 1998 at an average acquisition price of $94.50 per acre, 31 percent lower than the 1997 average cost of $137.47 per acre.

During the year the Company entered into a regional farmin and joint venture agreement with PanCanadian Petroleum Ltd. The farmin provides the Company with access to approximately 73,000 gross acres of undeveloped land in the Innisfail, Sylvan Lake, Westerose and Wilson Creek areas. Under the terms of the farmin, the Company will drill at least eight commitment wells on the agreement lands by the end of the first quarter 1999. Additional drilling and geophysical commitments made by the Company will extend the earning phase on a rolling option basis.

1998 Land Acquisitions – Western Canada

	Gross Acres	Net Acres	Net Dollars	Average Cost ($) Per Acre
Province				
British Columbia	39,915	39,634	2,579,936	65.09
Alberta	40,169	38,314	4,785,963	124.91
Total	80,084	77,948	7,365,899	94.50

Undeveloped Land by Province

	1998		1997		1996	
Acres	Gross	Net	Gross	Net	Gross	Net
British Columbia	392,478	294,171	373,562	269,557	251,065	171,350
Alberta	582,744	382,972	758,009	449,913	872,565	420,620
Saskatchewan	–	–	–	–	8,706	8,532
Quebec	2,421,558	181,618	–	–	–	–
Total	3,396,780	858,761	1,131,571	719,470	1,132,336	600,502

Undeveloped Land Reconciliation

	Gross Acres	Net Acres
December 31, 1996	1,132,336	600,502
Development	(61,653)	(22,387)
Purchases/Additions	274,596	229,114
Expiries/Deletions	(88,380)	(40,081)
Disposals	(125,328)	(47,678)
December 31, 1997	1,131,571	719,470
Development	(54,830)	(43,784)
Purchases/Additions - Western Canada	128,167	115,502
Additions - Quebec	2,421,558	181,618
Expiries/Deletions	(76,924)	(48,916)
Disposals	(152,762)	(65,129)
December 31, 1998	3,396,780	858,761

FINDING & DEVELOPMENT COSTS

Cost of Reserve Additions

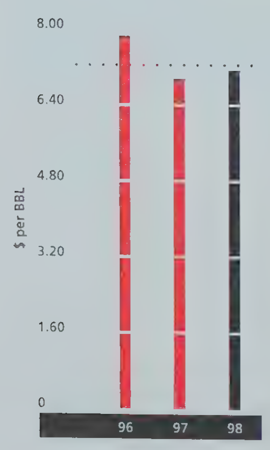
For 1998, finding costs were $4.62 per barrel of oil equivalent based on proven plus probable reserves added and $4.90 per barrel of oil equivalent for proven reserves added. Finding and development costs were $6.71 per barrel of oil equivalent on a proven plus probable basis and $7.13 per barrel of oil equivalent on a proven reserves basis. Finding costs include eastern Canada capital expenditures of $7.1 million with no corresponding reserve additions in 1998. Exploration in eastern Canada will continue in 1999 to further develop these high impact concepts.

In calculating finding and development costs, there are often a number of inconsistencies between periods created by the timing of expenditures and the phase of the exploration cycle. This is particularly related to land purchases and major facility construction, as well as the recognition and revision of reserves. Three year cumulative average calculations can be a more meaningful reflection of a company's ability to find and produce reserves effectively.

Finding and Development Costs

($ thousands)	Cumulative 1996-1998	1998	1997	1996
Total Finding Expenditures †	**310,539**	112,394	116,794	81,351
Total Development Expenditures †	**120,401**	51,112	41,360	27,929
Net Capital Expenditures	**430,940**	163,506	158,154	109,280
Proven				
Net Reserve Additions (mBOE) *	**59,623**	22,942	22,754	13,927
Finding Costs ($/BOE)	**5.21**	4.90	5.13	5.84
Finding and Development Costs ($/BOE)	**7.23**	7.13	6.95	7.85
Proven Plus 1/2 Probable				
Net Reserve Additions (mBOE) *	**63,896**	23,647	25,815	14,434
Finding Costs ($/BOE)	**4.86**	4.75	4.52	5.64
Finding and Development Costs ($/BOE)	**6.74**	6.91	6.13	7.57
Proven Plus Probable				
Net Reserve Additions (mBOE) *	**68,168**	24,351	28,876	14,941
Finding Costs ($/BOE)	**4.56**	4.62	4.04	5.44
Finding and Development Costs ($/BOE)	**6.32**	6.71	5.48	7.31

† *refer to net capital expenditures summary for details*
* *refer to reserve reconciliation table for details*



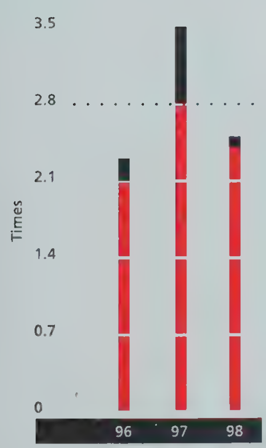
Finding and development costs (Proven)
····· three year average

Reserve Replacement

The Company's 1998 capital investment program replaced production by a factor of 2.5 times on a proven plus probable basis and 2.4 times on a proven basis.

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. It measures the efficiency of turning a barrel of oil equivalent of reserves into a new barrel of oil equivalent of production. It accomplishes this by measuring the operating netback per barrel of oil equivalent to that year's proven plus probable finding and development costs.



Reserve replacement ratio
..... three year average

Reserve Replacement

	Cumulative 1996-1998	1998	1997	1996
Production (mBOE)	24,412	9,743	8,189	6,480
Net Proven Reserve Additions (mBOE)	59,623	22,942	22,754	13,927
Proven Replacement Ratio	2.4	2.4	2.8	2.1
Proven Plus Probable Reserve Additions (mBOE)	68,168	24,351	28,876	14,941
Net Proven Plus Probable Replacement Ratio	2.8	2.5	3.5	2.3

Recycle Ratio

	Cumulative 1996-1998	1998	1997	1996
Operating Netback ($/BOE)	11.94	10.81	12.70	12.70
Proven Finding & Development Costs ($/BOE)	7.23	7.13	6.95	7.85
Proven Reinvestment Efficiency Ratio	1.7	1.5	1.8	1.6
Proven Plus Probable Finding & Development Costs ($/BOE)	6.32	6.71	5.48	7.31
Proven Plus Probable Reinvestment Efficiency Ratio	1.9	1.6	2.3	1.7

RESERVES

The crude oil and natural gas reserves of the Company were evaluated, effective December 31, 1998 by Gilbert Laustsen Jung Associates Ltd., independent petroleum engineering consultants.

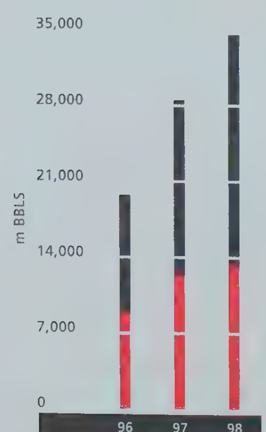
At year end 1998, Encal's proven plus probable crude oil and natural gas liquids reserves increased 17 percent to 47.8 million barrels from 40.9 million barrels in 1997. Proven plus probable natural gas reserves increased 13 percent to 682 billion cubic feet from 605 billion cubic feet in 1997. The Company's reserve life index is 7.6 years for proven and 10.6 years for proven plus probable crude oil and natural gas liquids reserves and 9.2 years for proven and 13.1 years for proven plus probable natural gas reserves.

Major technical revisions to proven reserves include increased recovery factors on the Rigel Cecil oil pools due to performance. Delineation work at Wilson Creek warranted pool reserve bookings and converted proven non-producing reserves into producing. Development of Rigel, Redeye and Wilson Creek fields has confirmed past probable reserve booking resulting in a significant shifting of these reserves from the probable to the proven category.

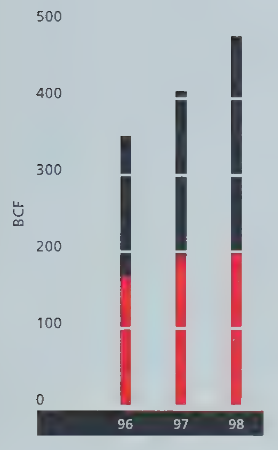
Rerouting of gas to other plants provided increased NGL recoveries for the Minehead, Columbia, Wilson Creek and Open Creek properties. Steeper declines at Cherhill, Columbia and Worsley resulted in some reductions to proven producing reserves.

Reserve Reconciliation - Oil & NGL (mbbls)

	Proven Producing	Proven Non-Producing	Total Proven	Probable	Proven Plus Probable
December 31, 1996	16,515	3,233	19,748	8,932	28,680
Extensions and Discoveries	6,888	2,975	9,863	3,343	13,206
Technical Revisions	(586)	542	(44)	(825)	(869)
Acquisitions	2,761	353	3,114	1,227	4,341
Dispositions	(654)	(102)	(756)	(253)	(1,009)
Reserve Additions	8,409	3,768	12,177	3,492	15,669
Production	(3,437)	–	(3,437)	–	(3,437)
December 31, 1997	21,487	7,001	28,488	12,424	40,912
Extensions and Discoveries	7,138	495	7,633	2,017	9,650
Technical Revisions	2,110	(399)	1,711	(1,019)	692
Acquisitions	2,141	318	2,459	534	2,993
Dispositions	(1,040)	(233)	(1,273)	(617)	(1,890)
Reserve Additions	10,349	181	10,530	915	11,445
Production	(4,520)	–	(4,520)	–	(4,520)
December 31, 1998	27,316	7,182	34,498	13,339	47,837



Crude oil & NGL reserves (Proven)



Natural gas reserves (Proven)

Reserve Reconciliation - Natural Gas (bcf)

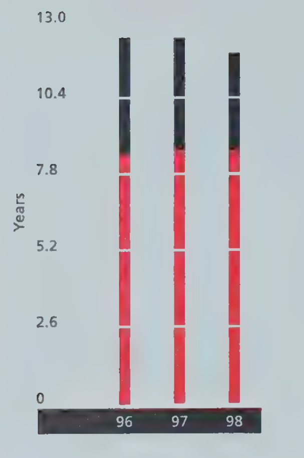
	Proven Producing	Proven Non-Producing	Total Proven	Probable	Proven Plus Probable
December 31, 1996	191.80	159.52	351.32	168.82	520.14
Extensions and Discoveries	77.88	29.16	107.04	37.33	144.37
Technical Revisions	9.21	(14.41)	(5.20)	(7.95)	(13.15)
Acquisitions	21.25	5.18	26.43	12.02	38.45
Dispositions	(10.69)	(11.81)	(22.50)	(15.10)	(37.60)
Reserve Additions	97.65	8.12	105.77	26.30	132.07
Production	(47.52)	–	(47.52)	–	(47.52)
December 31, 1997	241.93	167.64	409.57	195.12	604.69
Extensions and Discoveries	102.22	(1.16)	101.06	28.04	129.10
Technical Revisions	18.49	(13.38)	5.11	(19.89)	(14.78)
Acquisitions	46.61	5.58	52.19	11.85	64.04
Dispositions	(19.13)	(15.11)	(34.24)	(15.06)	(49.30)
Reserve Additions	148.19	(24.07)	124.12	4.94	129.06
Production	(52.23)	–	(52.23)	–	(52.23)
December 31, 1998	337.89	143.57	481.46	200.06	681.52

Net Reserve Additions

	Proven		Proven plus Probable	
	Oil & NGL	Natural Gas	Oil & NGL	Natural Gas
Province	(mbbls)	(bcf)	(mbbls)	(bcf)
British Columbia	5,979	48.3	7,916	61.2
Alberta	4,551	75.8	3,529	67.9
Total	10,530	124.1	11,445	129.1

Reserves

	Oil & NGL (mbbls)			Natural Gas (bcf)		
	Proven	Probable	Proven plus Probable	Proven	Probable	Proven plus Probable
Province						
British Columbia	15,648	5,983	21,631	153.0	66.1	219.1
Alberta	18,850	7,355	26,205	328.5	133.9	462.4
Total	34,498	13,338	47,836	481.5	200.0	681.5



Reserve life index

Reserve Life Index

	1998	1997	1996
Crude Oil & NGL			
Production (mbbls)	4,520	3,437	2,632
Proven Reserves (mbbls)	34,498	28,488	19,748
Proven Reserve Life Index (years)	7.6	8.3	7.5
Proven Plus Probable Reserves (mbbls)	47,837	40,912	28,680
Proven Plus Probable Reserve Life Index (years)	10.6	11.9	10.9
Natural Gas			
Production (bcf)	52.2	47.5	38.5
Proven Reserves (bcf)	481.5	409.6	351.3
Proven Reserve Life Index (years)	9.2	8.6	9.1
Proven Plus Probable Reserves (bcf)	681.5	604.7	520.1
Proven Plus Probable Reserve Life Index (years)	13.1	12.7	13.5

Net Future Capital Expenditures

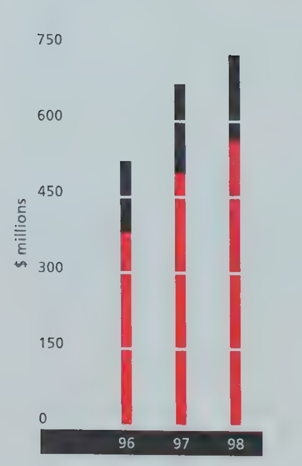
The reserve report incorporates future capital expenditure requirements to bring proven non-producing and probable reserves on production as well as to maintain proven producing reserves.

Net Future Capital Expenditures

Undiscounted ($ millions)	1998	1997	1996
Proven - Producing	5.1	4.2	2.9
Proven - Non-Producing	47.7	43.9	39.9
Total Proven	52.8	48.1	42.8
Probable	29.3	24.1	14.1
Total Proven Plus Probable	82.1	72.2	56.9

Present Value of Reserves

($ millions, before income taxes)	1998				1997				1996			
Discount Factor (%)	0	10	12	15	0	10	12	15	0	10	12	15
Proven	1,104	609	561	502	994	537	493	440	732	411	378	339
Probable	498	192	168	140	505	202	178	149	422	160	141	117
Total	1,602	801	729	642	1,499	739	671	589	1,154	571	519	456



Reserve value (NPV 12%)

Reserve Value Reconciliation

The Company's reserve value increased nine percent to $729 million (NPV 12 percent) at December 31, 1998 compared to $671 million at December 31, 1997.

Pricing Forecasts

The decrease in crude oil prices forecast by Gilbert Laustsen Jung in 1998 had a material impact on the value of the Company's reserves. The crude oil price forecast was reduced by approximately $2.00 (US WTI) per barrel for the forecast period. The natural gas pricing forecast is higher in the short term but lower in the long term. The differences between 1997 and 1998 price forecasts reduced Encal's 1998 reserve value by $38.0 million.

Reserve Value Reconciliation - (NPV 12%)

($ millions, before income taxes)	1998	1997	1996
Opening Reserve Value			
Proven Plus Probable	671	519	414
Net Present Value of Current Year Production	(105)	(104)	(82)
Net Present Value of Current Year Reserve Additions	201	257	202
Change in Value due to Pricing	(38)	(1)	(15)
Closing Reserve Value - Proven Plus Probable	729	671	519

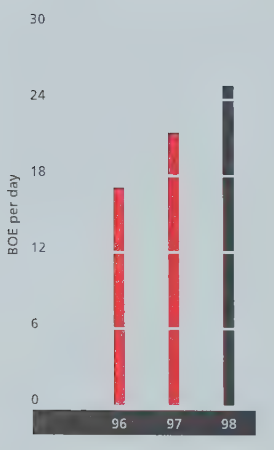
Pricing Assumptions (Gilbert Laustsen Jung Associates Ltd.)

	Crude Oil [1] (US $/bbl)			Crude Oil [2] (CDN $/bbl)			Natural Gas [3] (CDN $/mmbtu)		
Year	1998	1997	1996	1998	1997	1996	1998	1997	1996
1997			21.00			27.25			1.70
1998		19.00	19.00		25.75	24.75		1.70	1.75
1999	15.00	20.00	20.00	21.50	26.75	26.00	2.15	1.85	1.85
2000	17.00	20.75	21.00	23.50	27.25	27.25	2.25	2.00	2.00
2001	19.00	21.50	21.50	25.50	28.00	28.00	2.25	2.15	2.25
2002	20.00	22.00	22.00	26.00	28.75	28.75	2.30	2.30	2.35
2003	20.50	22.50	22.50	26.50	29.50	29.50	2.40	2.45	2.50
2004	21.00	23.00	23.00	27.00	30.00	30.00	2.50	2.60	2.60
2005	21.50	23.50	23.50	27.50	30.75	30.75	2.60	2.70	2.70
2006	22.00	24.00	24.00	28.25	31.25	31.25	2.65	2.75	2.75
2007	22.50	24.50	24.50	29.00	32.00	32.00	2.70	2.80	2.80
2008	22.75	25.00	+2.0%/yr	29.50	32.75	+2.0%/yr	2.75	2.90	+2.0%/yr
2009	23.25	+2.0%/yr		30.00	+2.0%/yr		2.80	+2.0%/yr	
Thereafter	+2.0%/yr			+2.0%/yr			+2.0%/yr		

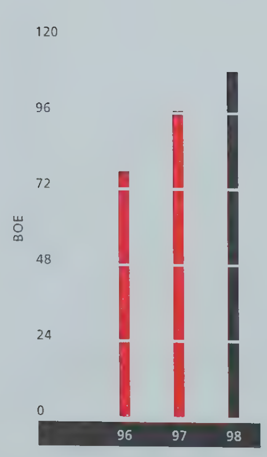
(1) West Texas Intermediate at Cushing, Oklahoma
(2) Light Sweet at Edmonton, Alberta
(3) TransCanada Gas Services at NOVA receipt point and 1,000 BTU/SCF

COMMON SHARE INFORMATION

Common Shares issued during 1998 were due to the exercise of 1,450,943 employee stock options. Employee stock options granted to employees during the year amounted to 2,733,501 shares. A total of 149,589 options were cancelled during the year. The Company has a total of 6,925,573 options outstanding with a weighted average exercise price of $4.34 per share. Other than the exercise of employee stock options, the Company has not issued equity since 1993.



Production per 100 shares



Reserves per 100 shares
(Proven plus probable)

COMMON SHARE INFORMATION (thousands)	1998	1997	1996
Outstanding Shares			
Weighted Average Outstanding Shares			
- Basic	**105,534**	104,421	103,851
- Fully Diluted	**111,684**	110,334	108,111
Outstanding Shares December 31			
- Basic	**106,235**	104,784	103,992
- Fully Diluted	**113,161**	110,577	109,922

($ thousands except per share amounts)			
Per Share Information			
Net Earnings	**2,737**	13,031	11,518
Net Earnings per Share			
- Basic	**0.03**	0.12	0.11
- Fully Diluted	**0.03**	0.12	0.11
Cash Flow from Operations	**74,144**	84,101	66,195
Cash Flow from Operations per Share			
- Basic	**0.70**	0.81	0.64
- Fully Diluted	**0.67**	0.77	0.62
Total Asset Value	**630,039**	514,132	410,141
Total Asset Value per Share *			
- Basic	**5.93**	4.91	3.94
- Fully Diluted	**5.57**	4.65	3.73
Book Value (Shareholders' Equity)	**276,863**	269,228	253,736
Book Value per Share *			
- Basic	**2.61**	2.57	2.44
- Fully Diluted	**2.45**	2.43	2.31
Production (BOE per day)	**26,694**	22,436	17,803
Production per 100 Shares *			
- Basic	**25.1**	21.4	17.1
- Fully Diluted	**23.6**	20.3	16.2
Proven plus Probable Reserves (mBOE)	**115,989**	101,381	80,694
MBOE Reserves per 100 Shares *			
- Basic	**109.1**	96.8	77.6
- Fully Diluted	**102.5**	91.7	73.4

** Calculated using outstanding shares at year end*

CAPITALIZATION & FINANCIAL RESOURCES

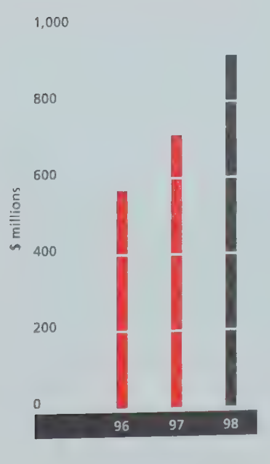
The Company's total capitalization increased 29 percent to $920.2 million during 1998 with the market value of common shares representing 66 percent of total capitalization. Debt, including working capital deficiency, represented 26 percent of total capitalization. Site restoration and reclamation costs and future income taxes accounted for eight percent. The total market value of the Company's common shares increased to $605.5 million largely as a result of share price appreciation. The only common shares issued during 1998 were the result of the exercise of employee stock options.

Net Asset Value Per Share

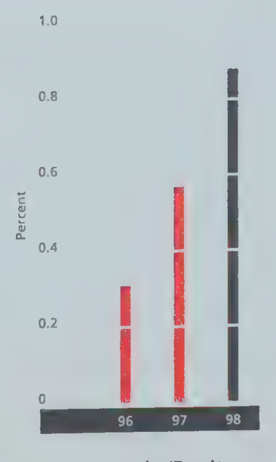
($ thousands)	1998	1997	1996
Reserve Value (12% discount before tax)	729,000	671,000	519,000
Undeveloped Acreage	62,759	66,825	50,851
Seismic and Other Assets	35,000	30,000	25,000
Working Capital Deficiency	(20,968)	(10,409)	(14,961)
Bank Debt	(146,736)	(71,959)	(64,046)
Senior Notes Payable	(76,525)	(71,455)	–
Total - Basic	582,530	614,002	515,844
Exercise of Stock Options	29,810	20,611	19,797
Total - Fully Diluted	612,340	634,613	535,641
Net Asset Value per Common Share ($)			
- Basic	5.48	5.86	4.96
- Fully Diluted	5.41	5.74	4.87

Capitalization and Financial Resources

($ thousands except per share amounts)	1998	%	1997	%	1996	%
Common Shares Outstanding (thousands)	106,235		104,784		103,992	
Share Price - ($) December 31 on TSE	5.70		4.70		4.29	
Market Capitalization	605,540	66	492,485	69	446,126	77
Working Capital Deficiency	20,968	2	10,409	2	14,961	3
Bank Debt	146,736	16	71,959	10	64,046	11
Senior Notes Payable	76,525	8	71,455	10	–	–
Total Debt	244,229	26	153,823	22	79,007	14
Site Restoration and Reclamation	9,403	1	8,233	1	7,021	1
Future Income Taxes	61,034	7	58,559	8	44,959	8
Total Capitalization	920,206	100	713,100	100	577,113	100
Total Debt to Total Capitalization (%)	26.54		21.57		13.69	



Capitalization



Debt/Equity

Financial Resources

Long term debt consists of $76.5 million (US$50 million) senior unsecured notes and $146.7 million of bank borrowing resulting in total long term debt of $223.3 million. The Company's credit facilities total $300.0 million.

At December 31, 1998, the working capital deficiency was $21.0 million compared to $10.4 million at December 31, 1997. During periods of active capital expenditure programs the Company normally operates in a working capital deficiency.

Senior Notes Payable consist of US$50.0 million unsecured notes. The Notes carry a 10 year term, bear interest at 7.61 percent and are repayable in five equal annual payments of US$10.0 million commencing on July 11, 2003. This transaction allows the Company to term out a portion of its core debt and is a natural hedge to our US dollar denominated revenue.

Long term debt and working capital deficiency amounted to $244.2 million at year end. This total debt level represents approximately 3.29 times 1998 cash flow from operations of $74.1 million. Cash flow for 1998 includes non-recurring crude oil and foreign exchange hedging charges of $6.9 million. Total debt at December 31, 1998 to estimated 1999 cash flow is 2.12 times.

Key Debt Ratios

($ thousands)	1998	1997	1996
Bank Debt	146,736	71,959	64,046
Senior Notes Payable	76,525	71,455	–
Total Long Term Debt	223,261	143,414	64,046
Working Capital Deficiency	20,968	10,409	14,961
Total Debt	244,229	153,823	79,007
Cash Flow from Operations	74,144	84,101	66,195
Years Cash Flow to Repay Total Debt			
- Trailing	3.29	1.83	1.19
- Forward	2.12	2.07	0.94
Asset Coverage Ratio			
Total Assets	630,039	514,132	410,141
Total Debt	244,229	153,823	79,007
Asset Coverage	2.58	3.34	5.19
Total Debt/Equity Ratio			
Total Debt	244,229	153,823	79,007
Shareholders' Equity	276,863	269,228	253,736
Total Debt/Equity	0.88	0.57	0.31
Total Long Term Debt/EBITDA			
Total Long Term Debt	223,261	143,414	64,046
EBITDA	88,264	92,425	69,284
Total Long Term Debt/EBITDA	2.53	1.55	0.92

RISK ASSESSMENT

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks and includes Encal's approach to managing these risks.

Commodity Risks

Finding

Oil and gas exploration requires manpower and capital to generate and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves. Encal attempts to minimize finding risk by ensuring that:

- The majority of prospects have multi-zone potential.
- Activity is focused in core regions where expertise and experience is greatest.
- Number of wells drilled is large enough to ensure the continuity of historic success rates.
- Working interests are targeted at over 60 percent in new prospects.
- Geophysical techniques are utilized where appropriate.

Investment Risk Profile

The capital budgeting process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth (development activity) and future cash flow from the discovery of reserves (exploration). As a result of this process, evaluation of play types and development of a potential drilling list for 1999, we expect to dedicate 65 percent of the exploration capital budget to plays that will add reserves in 1999 and potentially lead to development activities in 2000 and beyond. Thirty-five percent will be dedicated to play types that will add to the current year's cash flow.

Production

Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. Encal minimizes this risk by generating prospects internally, targeting high quality products and attempting to operate the associated project. Operational control allows the Company to control costs, timing, method and sales of production. Production risk is also minimized by concentrating efforts in regions where facilities and infrastructure are Encal-owned, or the Company can control the future development of new facilities and infrastructure.

Financial and Liquidity Risks

Encal relies on various sources of funding to support its growing capital expenditures program:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditures program is based.
- Debt may be utilized to expand capital programs when it is deemed appropriate.
- New equity, if available and if on favorable terms, will be utilized to expand exploration programs.

Cash flow is influenced by factors which the Company cannot control, such as commodity prices, the US/CDN dollar exchange rate, interest rates and changes to existing government regulations and tax policies. Should circumstances affect cash flow in a detrimental way, Encal would respond by increasing debt to within the Company's self-imposed debt guideline or reducing capital expenditures. The Company uses farm-outs to minimize risk on plays it considers high risk.

Environmental and Safety Risks

There are potential risks to the environment inherent in the business activities of the Company. The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of shareholders, employees and the public at large. The Company mitigates environmental and safety risks by maintaining modern facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

In September 1998, the Company completed a comprehensive independent three part environmental audit initiated in 1996, that assessed all Encal operated properties. No significant issues related to the audit are outstanding. In addition to this auditing program, Encal furthered its proactive environmental responsibilities through its involvement in Canada's National Action Plan on Climate Change. As a consequence of its initiatives, Encal was awarded the Voluntary Challenge and Registry recognition for "Best New Submission" resulting from its 1997 action plan to reduce its operational green house gas emissions.

The Company has estimated future site restoration and abandonment costs will total $21.6 million and has recognized $2.1 million through increased depletion in 1998. The Company reviews its site restoration and abandonment obligations annually and adjusts its provision based on current costs. As well, the Company allocates a portion of its annual budget to decommissioning and site reclamation each year.

Inflation Risk

Inflation risks subject the Company to potential erosion of product netbacks. For example, increasing domestic prices for oil and gas production equipment and services can inflate the costs of operating the production.

Supply of Service and Production Equipment

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long term relationships with suppliers and contractors and from time to time will enter into long term service contracts. The Company also maintains an appropriate inventory of production equipment.

Risk Management

The objectives of Encal's risk management policy are to secure the capital program and cover debt payments by ensuring that budgeted cash flow levels are attained through the minimization of exposure to commodity price, foreign exchange and interest rate volatility. The objectives are achieved through the use of financial instruments or by negotiating fixed price contracts on the delivery of physical volumes. The program is subject to certain targets and guidelines as approved by the Board of Directors from time to time. Effective controls and procedures are in place to ensure that the mandate is followed.

Marketing Risks

Demand for crude oil and natural gas produced by the Company exists within Canada and the United States, however, prices for crude oil are affected by worldwide supply and demand while natural gas prices are limited by North American supply and demand fundamentals. Demand for natural gas liquids is dictated predominantly by demand for petrochemicals in North America and offshore markets.

- Encal's historic oil production is of a high quality and hence not subject to adverse quality differentials.
- Encal's natural gas is connected to mature pipeline infrastructure which operates with minimal interruptions.
- Encal's exploration efforts plan on adding high quality oil and liquid rich natural gas reserves.
- Encal concentrates exploration efforts in core regions where marketing expertise levels are highest. Marketing synergies can be achieved with the existing production base.
- Encal enters into sales arrangements which vary in term and pricing structure to develop a portfolio to minimize risk of exposure to any one market.
- Encal uses financial instruments where appropriate to manage commodity pricing in order to reduce volatility.

Technology Risks

The Company relies on information technology to manage its day to day operations and perform its reporting obligations including the preparation of financial statements, reporting to joint partners and various governments in relation to payment of royalties and taxes.

Year 2000

Like other companies, Encal is vulnerable to the failure of its computerized systems and those of its key business partners, such as customers, suppliers, utilities, government agencies and other third parties. Computers, information technology and electronics are widely used throughout Encal to facilitate effective and efficient operations and administration. Most of these systems are industry standard and the Company acquires known technology rather than developing its own technology in relation to business systems. The Company recognized that a coordinated approach was necessary to deal with the fact that date sensitive functions in computer hardware/software and in embedded systems may fail to accurately process dates before, during and after the year 2000.

Risks of the Year 2000 Issue

It is the Company's goal to avoid any disruptions of services before, during and after the Year 2000. Because of the unique nature of the Year 2000 issue and the Company's reliance on other significant product and service suppliers, customers and business partners, unanticipated problems remain a possibility. There can be no assurance that all of the Company's Year 2000 remediation efforts will be completely successful. The impact of a failure to complete such remediation efforts successfully could have a material adverse effect on the Company's results of operations, financial position or liquidity.

Transition Committee

In early 1998 the Company established a Year 2000 Transition Committee, comprised of senior management members from a cross section of functional disciplines, to direct and manage the transition through the year 2000. The Committee mandate is to assess the Company's year 2000 exposure, remedial effected systems, develop appropriate contingency plans and business resumption processes. The current focus of the Committee includes conversion, testing, correction of deficiencies within critical business systems, coordinating vendor supplied systems software upgrades, developing contingency plans and assessing the Year 2000 plans and progress of key business partners.

In addition, external consultants have been retained to comment on the approach, structure and completeness of the Company's Year 2000 planning process. The consultants are also commenting on critical system vendor's readiness with respect to the extent of Year 2000 testing, problem resolution and quality assurance processes.

The Committee reports to the Audit Committee and the Board of Directors quarterly.

Critical Systems

Critical Business Systems

Critical systems include financial accounting, production accounting, land administration, marketing, field production volume reporting, desktops and networks.

Desktop and Network systems – Installation of vendor provided software modifications are complete with compliance for known deficiencies achieved for network systems. Minor revisions for the desktop systems are scheduled to be completed in April 1999.

Other critical business systems – As Encal's Year 2000 evaluation of critical business systems has evolved, it has become aware of various minor Year 2000 issues not previously identified. In some cases minor upgrades are required as vendors continue their respective Year 2000 evaluations and testing. As a result, various vendor upgrades and conversions are required for Encal to be Year 2000 compliant. These upgrades and conversions have been identified and are currently underway and are scheduled to be completed at various dates between April and June 1999.

Encal's Year 2000 review has identified a critical business system involving the reporting of royalties that is not compliant. The vendor has delivered a new version of the product that is currently being installed that should rectify any compliance issues by mid year. Year 2000 testing of critical business applications is planned and will proceed after completion of respective conversions and/or upgrades. This testing is scheduled to be completed by July 1999.

Critical Field Equipment

A review of Company operated field equipment has been completed. Summary findings indicate 75 percent of the field equipment base is mechanical and does not contain programmed logic and has been confirmed compliant by the vendor. The balance of equipment includes two SCADA (Supervisory Control and Data Acquisition) sites both of which have been confirmed compliant. The Company continues to research and evaluate field equipment. A second level review is underway and planned to be completed by May 1999 with testing scheduled to be completed by August 1999 and repair or replacement (if necessary) scheduled to occur by September 1999.

A survey of process control equipment managed by other operators is underway. This process has categorized the Company's risk exposure by operator. Communication with these partners has commenced and responses are being followed up.

The Company has a representative on the Industry Joint Effort, a group of oil and gas producers that have organized to share Year 2000 related information and testing results related to field operational equipment. The activities of this group will help reduce the time required to identify and test field equipment which may not be Year 2000 compliant.

Completion Dates

The Company has scheduled completion dates for all the remediation and testing of critical systems. The scheduled completion dates are based on the information currently available to the Company and are subject to change.

Vital Systems

This category represents products and software that are important to the operation of the Company but would not jeopardize its ability to maintain operations and deliver product. This includes various engineering, production, exploration and administrative tools. Vendors have been contacted and all products have been assessed. Of these products, 90 percent are Year 2000 compliant and 10 percent require product modifications to ensure compliance. The projected completion date for the application and testing of upgrades is July 1999.

Key Business Partners

The Company is conducting a review of key business partners and their respective Year 2000 programs. Partners are being categorized by importance to continued business operations and product delivery. Continued dialogue is planned with key business partners to ensure that they are properly positioned for the Year 2000 and are able to deliver services. It is not possible for Encal to ensure that partners will be compliant.

Costs to Address the Year 2000 Issue

Costs associated with Year 2000 compliance efforts are being capitalized where they relate to new products or upgrades that extend product life while remaining expenditures will be expensed. The Company does not anticipate that the costs of this initiative will have a material impact on financial or operating results. To date, the Company has spent approximately \$150,000 to rectify recognized Year 2000 compliance issues. These costs include software and hardware upgrades required to be Year 2000 compliant (but also may include functional improvements beyond Year 2000 readiness) and consulting charges related to the Year 2000 effort. Allocation of costs related to employee time devoted to Year 2000 readiness is estimated to be approximately \$50,000. Encal estimates that over the life of the project, Year 2000 expenditures are expected to total approximately \$500,000. The Company's Year 2000 estimates of expenditures is based on current information and various assumptions and are subject to change.

Contingency Planning

As the Company's Year 2000 initiative evolves, it continues to assess its risk exposure and will develop contingency plans to deal with these risks. These plans will be designed to protect the Company's assets, continue safe operations, protect the environment and enable the resumption of any interrupted operations in a timely and efficient manner. These plans are scheduled to be in place by the second half of 1999.

Encal cannot guarantee the Year 2000 readiness of third parties. Its contingency planning activities will include, where practical and feasible, identifying alternative sources of products or services, establishing a team of experienced personnel to manage issue resolution and dispatch resources, and prepare manual solutions for critical processes dependent on date sensitive technology.

State of Readiness

Encal believes it has the appropriate plans and resources in place to achieve timely Year 2000 readiness for its critical systems. The Company defines Year 2000 readiness as the date when its critical systems are rectified and the changes have been tested and implemented, or there are contingency plans or alternate arrangements for the systems that have not been rectified.

OUTLOOK & PROSPECTS FOR FUTURE GROWTH

Encal remains confident of its ability for success and future growth. The Company believes it can deliver base production growth of 20 percent for 1999 from its internal exploration and development program.

Growth results from the efficient reinvestment of cash flow. Annual cash flow is not only determined by product prices but by production volumes, which are in turn influenced by annual capital expenditure levels. Management has prepared the 1999 Cash Flow Commodity Sensitivities table to assist the reader in understanding the interrelationship of commodity prices and cash flow. The current commodity price environment is sufficient to justify planned exploration and development expenditures, provided efficient finding and development costs and operating costs are maintained.

1999 Capital Budget

The Company has an approved capital budget net of dispositions of $150.0 million for 1999. The Board of Directors reviews the capital budget every quarter and will amend capital spending if required. With a surplus inventory of exploration and development prospects, selectivity will maximize returns.

The 1999 capital budget has been established utilizing commodity price forecasts of US$13.00 WTI per barrel for crude oil and an average of $2.40 per thousand cubic feet for natural gas.

1999 Cash Flow Commodity Sensitivities

($ millions)	WTI (US$/bbl)			
	12.00	13.00	14.00	15.00
Average Gas Price ($/mcf)				
2.20	95	100	105	110
2.30	100	105	110	115
2.40	105	110	115	120
2.50	110	115	120	125

1999 Sensitivities

($ thousands)	Cash Flow from Operations	Earnings
Impact on 1999:		
Change in West Texas Intermediate oil price by US$1.00 per barrel	5,200	2,900
Change in average field price of natural gas by CDN$0.10 per mcf	5,500	3,000
Change in value of CDN dollar compared to US dollar by CDN $0.01	700	400
Change of 1% in prime interest rates	1,700	950

(above assumes a US dollar exchange rate of $1.5244)

1999 Capital Budget

($ millions)	
Exploration and Development Capital	120
Facility Capital	50
Dispositions	(20)
Total Capital	150

MANAGEMENT'S REPORT

The accompanying financial statements of Encal Energy Ltd. and all the information in this annual report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Encal Energy Ltd. maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and all of its members are outside directors. The Committee meets periodically with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities and to review the annual report, the financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. Ernst & Young LLP has full and free access to the Audit Committee.

Steven A. Allaire

Vice President Finance and CFO

David D. Johnson

President and CEO

Calgary, Canada

February 23, 1999

AUDITORS' REPORT

To the Shareholders of Encal Energy Ltd.

We have audited the balance sheets of Encal Energy Ltd. as at December 31, 1998 and 1997 and the statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 1998. These financial statements are the responsibility of the management of the Company. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 1998 in accordance with accounting principles generally accepted in Canada.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada

February 23, 1999

Encal Energy Ltd.

Balance Sheets

As at December 31 *($ thousands)*	1998	1997
		(Restated - Note 1)
Current		
Accounts Receivable	28,303	18,366
Inventory	10,207	5,923
	38,510	24,289
Petroleum Property and Equipment *(Note 3)*	584,512	487,137
Deferred Foreign Exchange Losses *(Note 5)*	7,017	2,706
	630,039	514,132
Liabilities and Shareholders' Equity		
Current		
Accounts Payable	59,478	34,698
Bank Debt *(Note 4)*	146,736	71,959
Senior Notes Payable *(Note 5)*	76,525	71,455
Site Restoration and Reclamation	9,403	8,233
Future Income Taxes	61,034	58,559
Commitments and Contingencies *(Note 9)*	–	–
	293,698	210,206
Shareholders' Equity		
Share Capital *(Note 6)*	249,407	244,509
Retained Earnings	27,456	24,719
	276,863	269,228
	630,039	514,132

See accompanying notes

On behalf of the Board:

Director

Director

Statements of Earnings and Retained Earnings

For the years ended December 31 *($ thousands except per share amounts)*	1998	1997	1996
		(Restated - Note 1)	
Revenues			
Petroleum and Natural Gas Sales	176,463	170,624	129,110
Royalties	29,269	31,575	18,863
Hedging Charges *(Note 7)*	6,867	2,778	4,816
	140,327	136,271	105,431
Expenses			
Production	41,910	35,052	27,937
General and Administrative	10,153	8,794	8,210
Financing Charges	13,362	7,369	2,322
Depletion and Depreciation	68,200	57,400	46,127
	133,625	108,615	84,596
Earnings Before Taxes	6,702	27,656	20,835
Taxes			
Future Income Taxes *(Note 8)*	2,475	13,600	8,550
Capital Taxes	1,490	1,025	767
	3,965	14,625	9,317
Net Earnings for the Year	2,737	13,031	11,518
Retained Earnings, Beginning of Year	24,719	11,688	170
Retained Earnings, End of Year	27,456	24,719	11,688
Earnings Per Share			
Basic	0.03	0.12	0.11
Fully Diluted	0.03	0.12	0.11

See accompanying notes

Statements of Cash Flows

For the years ended December 31 *($ thousands except per share amounts)*	1998	1997	1996
		(Restated - Note 1)	
Cash Flows From Operating Activities			
Net Earnings for the Year	2,737	13,031	11,518
Depletion and Depreciation	68,200	57,400	46,127
Future Income Taxes	2,475	13,600	8,550
Amortization of Deferred Foreign Exchange Losses *(Note 5)*	732	70	–
Cash Flows From Operating Activities	74,144	84,101	66,195
Change in Non-Cash Working Capital *(Note 2)*	159	9,893	(616)
	74,303	93,994	65,579
Cash Flows From Financing Activities			
Bank Debt	74,777	7,913	35,920
Senior Notes Payable *(Note 5)*	27	68,679	–
Common Shares	4,898	2,461	516
	79,702	79,053	36,436
Cash Flows From Investing Activities			
Additions to Petroleum Property and Equipment	(148,121)	(141,249)	(96,978)
Acquisitions of Petroleum Property and Equipment	(64,454)	(56,470)	(24,645)
Sales of Petroleum Property and Equipment	49,069	40,161	12,343
Site Restoration and Reclamation	(899)	(1,044)	(1,043)
Change in Non-Cash Working Capital *(Note 2)*	10,400	(14,445)	8,308
	(154,005)	(173,047)	(102,015)
Change in Cash	–	–	–
Cash Flows From Operations Per Share			
Basic	0.70	0.81	0.64
Fully Diluted	0.67	0.77	0.62

See accompanying notes

Notes to Financial Statements

December 31, 1998, 1997 and 1996

1. Significant Accounting Policies

Nature of Business and Basis of Presentation

Encal Energy Ltd. (the Company) operates in the oil and gas industry in Alberta and British Columbia. The financial statements include the accounts of the Company and are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). A summary of the differences between accounting principles generally accepted in Canada and those generally accepted in the United States ("US GAAP") is contained in Note 10 to these statements.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Inventory

Inventory is carried at the lower of cost and net realizable value.

Petroleum Property and Equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties. All costs relating to the acquisition of, exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, lease and well equipment, and overhead expenses related to acquisition and exploration activities. General and administrative expenses are not capitalized other than to the extent of the working interest in Company-operated capital expenditure programs to which operator's fees have been charged pursuant to standard industry operating agreements.

Proceeds from disposal of properties are normally applied as a reduction of the cost of remaining assets without recognition of a gain or loss unless the disposal would result in a change of 20 percent or more in the depletion rate.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed estimated future net revenues from production of proven reserves at year end market prices less future production, general and administrative, financing, site restoration and reclamation, net of salvage values, and income tax costs plus the lower of cost or estimated market value of unproved properties.

Depletion of petroleum and natural gas properties is calculated using the unit-of-production method based on estimated proven oil and gas reserves. Reserves are converted to common units on the approximate equivalent energy basis.

Depreciation of corporate assets is provided using the straight line method, based on the estimated service lives of the related assets, as appropriate.

Site Restoration and Reclamation

The Company provides for the total future liability for site restoration and reclamation costs on wells and facilities using the unit-of-production method over the estimated life of the oil and gas reserves. The liability is based on estimates of the anticipated method and extent of site restoration, using current costs and in accordance with existing legislation and industry practice. The annual charge of $2,069,000 (1997 - $2,256,000; 1996 - $2,176,000) is grouped with depletion and depreciation expense, with the accumulated provision being shown as a deferred liability. Actual site restoration costs are deducted from the provision in the year incurred.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at year end exchange rates. Exchange gains or losses are included in earnings with the exception of the unrealized gains or losses on translation of long term monetary liabilities, which are deferred and amortized over the remaining terms of such liabilities on a straight line basis.

Measurement Uncertainty

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment and for site restoration and reclamation are based on estimates of reserves and future costs. By their nature, these estimates and those related to the future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Joint Operations

Substantially all of the exploration and production activities of the Company are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Per Share Information

Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal year. Fully diluted per share information is calculated on the basis of the weighted average number of common shares that would have been outstanding during the year had all the stock options been exercised at the date of their issuance.

Derivative Financial Instruments

The Company utilizes derivative financial instrument contracts to reduce its exposure to changes in petroleum and natural gas prices, the Canada/US dollar exchange rate and interest rates. Where petroleum and natural gas price swaps based in US dollars are entered into, the Company may use forward foreign exchange contracts to hedge against unfavourable Canada/US dollar exchange rates. Gains and losses incurred on these contracts are recognized in income concurrently with the hedged transaction. In the case of interest rate swaps, the differential to be paid or received is accrued as interest rates change and is recognized over the term of the agreements. The fair values of these contracts are not reflected in the financial statements.

Future Income Taxes

As recommended by The Canadian Institute of Chartered Accountants, effective January 1, 1998, the Company adopted the liability method of tax allocation in accounting for income taxes on a retroactive basis from January 1, 1995. The effect of adopting the new recommendations was to increase petroleum property and equipment and future income tax liability by $596,000 and $6,971,000 respectively, as at December 31, 1998 (1997 - $596,000 and $8,822,000 respectively) and to decrease future income tax expense and increase net income by $1,851,000 ($0.02 per share), nil ($0.00 per share), nil ($0.00 per share) for the years ended December 31, 1998, 1997 and 1996 respectively, and to decrease retained earnings by $6,375,000, $8,226,000, $8,226,000 $8,226,000 for the years ended December 31, 1998, 1997, 1996 and 1995 respectively.

Under the liability method, future tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Prior to the adoption of the new recommendations, income tax expense was determined using the deferral method of tax allocation. Future tax expense was based on items of income and expense that were reported in different years in the financial statements and tax returns and measured at the rate in effect in the year the differences originated.

Comparative Figures

Certain comparative figures have been reclassified or restated to conform with the current financial statement presentation.

2. Changes in Non-Cash Working Capital

($ thousands)	1998	1997	1996
Cash provided by (used for):			
Accounts Receivable	(9,937)	526	3,898
Inventory	(4,284)	(3,341)	1,932
Deposit	–	4,540	(4,540)
Accounts Payable	24,780	(6,277)	6,402
Changes in Non-Cash Working Capital	10,559	(4,552)	7,692

These changes relate to the following activities:			
Operating Activities	159	9,893	(616)
Investing Activities	10,400	(14,445)	8,308
	10,559	(4,552)	7,692

Cash Payments for Interest and Income Taxes			
Interest Paid on Debt	8,958	3,923	1,882
Capital Taxes Paid	1,549	920	622
	10,507	4,843	2,504

3. Petroleum Property and Equipment

($ thousands) December 31, 1998	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and Natural Gas Properties	832,672	(251,297)	581,375
Corporate Assets	7,349	(4,212)	3,137
	840,021	(255,509)	584,512

($ thousands) December 31, 1997	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and Natural Gas Properties	671,205	(187,049)	484,156
Corporate Assets	5,310	(2,329)	2,981
	676,515	(189,378)	487,137

Included in petroleum property and equipment is the amount of $64,836,000 (1997 - $66,825,000) representing the cost of undeveloped lands for which no depletion has been provided.

4. Bank Debt

The Company has an unsecured $194.0 million term credit facility and a $30.0 million operating credit facility from Canadian chartered banks of which $146.7 million was outstanding under the term credit facility at December 31, 1998 (1997 - $72.0 million). The interest rate on outstanding debt varies but approximates the lenders' prime rate (1998 - 6.61 percent; 1997 - 4.77 percent). The Company has the option (subject to bank approval) of converting its term credit facility to a reducing credit facility in whole or in part. Payments under the reducing facility would be required on a semi-annual basis in order that the facility be repaid by the maturity date of December 31, 2002. The facility provides for various interest rate and Bankers Acceptance fee options, which are based on market rates in effect from time-to-time. Financial covenants include long term debt not to exceed the borrowing base limit of $300.0 million and annual cash flows from operating activities before financing charges are greater than three times financing charges. The Company is in compliance with all of these covenants. The Company has an interest rate swap outstanding at December 31, 1998 (Note 7).

5. Senior Notes Payable

The senior notes payable represent $76.5 million (US$50.0 million) of 7.61 percent senior unsecured notes with a ten year term maturing July 11, 2007. The notes are repayable in five equal installments of US$10.0 million beginning July 11, 2003 with interest payable semi annually in arrears until maturity. The debt ranks equally with the Company's other debt obligations and is subject to certain financial covenants. Financial covenants include a maximum ratio of total debt excluding working capital to cash flows from operating activities plus financing charges of 3.0:1. The aggregate deferred foreign exchange loss arising upon translation of the notes at the year end rate was $7.0 million (1997 - $2.7 million) net of accumulated amortization.

6. Share Capital

Authorized

Unlimited number of Class A preferred shares issuable in series

Unlimited number of Class B preferred shares issuable in series

Unlimited number of common shares at no par value

Issued and Outstanding Common Shares

($ thousands except share amounts)	Number	Value
Balance at December 31, 1995	103,834,759	241,532
Issued Pursuant to the Exercise of Stock Options	157,564	516
Balance at December 31, 1996	103,992,323	242,048
Issued Pursuant to the Exercise of Stock Options	791,838	2,461
Balance at December 31, 1997	104,784,161	244,509
Issued Pursuant to the Exercise of Stock Options	1,450,947	4,898
Balance at December 31, 1998	106,235,108	249,407

The number of weighted average shares outstanding (basic) is 105,533,966 (1997 - 104,420,793; 1996 - 103,851,000).

Stock Options

Under the terms of the stock option plan, options to purchase common shares may be granted to management, employees and directors at an exercise price and exercise period as determined by the Board of Directors. All outstanding options were granted for a five year term. At December 31, 1998, options to purchase 6,925,573 common shares were outstanding at prices ranging from $2.66 to $6.00 per share and expiring between 1999 to 2003.

Included in the outstanding option amount are 1,625,000 incentive options; 1,400,000 of which were granted to the Company's executive officers on December 6, 1996 at an exercise price of $3.65 and 225,000 granted to an executive officer on March 24, 1997 at an exercise price of $4.10. The incentive options become exercisable as to 33.33 percent on the market price of the Corporation's common shares reaching $5.74, being reflective of a 12 percent compound annual growth rate over four years from the date of grant and as to 66.67 percent on the market price of the Corporation's common shares reaching $6.38, being reflective of a 15 percent compound annual growth rate over four years from the date of grant. An additional 541,667 incentive options were granted to the executive officers on July 29, 1998 at an exercise price of $5.74. These options become exercisable as to 33.33 percent on the market price of the Corporation's common shares reaching $9.03, being reflective of a 12 percent compound annual growth rate over four years from the date of grant and as to 66.67 percent on the market price of the Corporation's common shares reaching $10.04, being reflective of a 15 percent compound annual growth rate over four years from the date of grant.

Activity in the plan through December 31, 1998 was as follows:

Options Outstanding

($ thousands except share amounts)	Number of Shares	Price Per Share	Total Price
Balance at December 31, 1995	4,224,300	2.38 - 4.60	$ 13,385
Options Granted	2,311,250	2.80 - 4.00	8,342
Options Cancelled	(447,918)	2.66 - 3.55	(1,414)
Options Exercised	(157,564)	2.38 - 3.55	(516)
Balance at December 31, 1996	5,930,068	2.38 - 4.60	$ 19,797
Options Granted	976,800	4.10 - 5.35	4,332
Options Cancelled	(322,573)	2.66 - 5.10	(1,057)
Options Exercised	(791,691)	2.38 - 3.65	(2,461)
Balance at December 31, 1997	5,792,604	2.66 - 5.35	$ 20,611
Options Granted	2,733,501	4.40 - 6.00	14,641
Options Cancelled	(149,589)	2.70 - 5.10	(545)
Options Exercised	(1,450,943)	2.66 - 4.70	(4,897)
Balance at December 31, 1998	6,925,573	2.66 - 6.00	$ 29,810

Additional details on the Company's stock options outstanding at December 31, 1998 are as follows:

Range of Exercise Prices ($/share)	Outstanding Options: Number of Options	Weighted Average Exercise Price ($/share)	Weighted Average Years to Expiry	Exercisable Options: Number of Options	Weighted Average Exercise Price ($/share)
2.66 - 3.99	3,297,255	3.41	2	2,157,032	3.30
4.00 - 4.99	789,017	4.27	3	243,772	4.26
5.00 - 6.00	2,839,301	5.44	5	265,333	5.31
2.66 - 6.00	6,925,573	4.34	3	2,666,137	3.58

As at December 31, 1998, the Company has reserved 1,063,145 common shares for future issuance under the plan.

7. Financial Instruments

The Company's financial instruments recognized in the balance sheets consist of accounts receivable, accounts payable, bank debt and senior notes payable. The fair value of these financial instruments approximates their carrying amounts. The Company's hedging (gains) charges are as follows:

($ thousands)	1998	1997	1996
Crude Oil Hedging (Gains) Charges	(3,467)	1,245	4,732
Crude Oil Foreign Exchange Hedging Charges	6,657	965	27
Natural Gas Foreign Exchange Hedging Charges	3,677	568	57
Total Hedging Charges	6,867	2,778	4,816
Financing Charges - Interest Rate Swap (Gains) Charges	(29)	647	324

The Company is a party to certain off-balance sheet financial derivative instruments, including crude oil, natural gas, foreign exchange and interest rate swap contracts. The Company enters into these contracts for the purpose of protecting its future Canadian dollar earnings and cash flow from operations from the volatility of crude oil and natural gas commodity prices, US/Canadian dollar exchange rates and interest rates. The swap contracts reduce fluctuations in petroleum and natural gas sales and financing charges, respectively, by locking in fixed forward prices on a portion of its petroleum and natural gas sales, locking in the associated forward foreign exchange exposure and locking in fixed interest rates on a portion of its floating rate debt.

Contracts outstanding in respect to financial instruments were as follows:

($ millions except where otherwise stated)	Quantity	Average Fixed Price/Rate $Canadian	Hedge Termination
As at December 31, 1998			
US Dollar Swaps	US$12	1.5416	Dec 99
	US$12	1.4500-1.6000*	Dec 99
Interest Rate Swaps	CDN$20	5.395%	Mar 99
	CDN$20	6.185%	Dec 99
As at December 31, 1997			
Crude Oil Swaps	20,000 barrels per month	US$20.73	Dec 98
	10,000 barrels per month	US$20.00-21.20**	Dec 98
US Dollar Swaps	US$93	1.3734	Dec 98
Interest Rate Swaps	CDN$20	5.395%	Mar 99
As at December 31, 1996			
Crude Oil Swaps	26,667 barrels per month	25.00-26.13	Mar 97
	20,000 barrels per month	25.00-26.13	Dec 97
	20,000 barrels per month	26.25-29.95***	Dec 97
US Dollar Swaps	US$29	1.3375	Dec 97
	US$24	1.3348	Dec 98
Interest Rate Swaps	CDN$20	6.27%	Jan 98

**costless collar with minimum floor of $1.450 and maximum ceiling of $1.600*
***costless collar with minimum floor of US$20.00 and maximum ceiling of US$21.20*
****costless collar with minimum floor of $26.25 and maximum ceiling of $29.95*

On settlement, these contracts result in cash receipts to or payments by the Company for the difference between the fixed contract and floating market rates for the applicable dollars and volumes fixed during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the Company's risk management losses or interest expense.

At December 31, 1998 the estimated fair values on these swap transactions were as follows:

($ thousands receivable (payable))	1998	1997	1996
Crude Oil Swaps	–	1,066	2,181
US Dollar Swaps	174	(4,437)	(442)
Interest Rate Swaps	(161)	(61)	(539)

The above estimated fair values are based on the market value of these financial instruments as at year end and represent the amounts the Company would receive or pay to terminate the contracts at year end. These instruments have no book values recorded in the financial statements.

The Company may be exposed to certain losses in the event of non-performance by counterparties to these contracts. The Company mitigates this risk by entering into transactions with major international financial institutions with appropriate credit ratings and ensuring that this credit risk is not concentrated with a small number of counterparties.

8. Future Income Taxes

The liability for future income taxes is primarily due to the excess carrying value of property plant and equipment over the associated tax basis.

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate income tax rate to earnings before income taxes. The major components of these differences are explained as follows:

($ thousands)	1998	1997	1996
Earnings Before Income Taxes	6,702	27,656	20,835
Corporate Income Tax Rate	44.87%	44.78%	44.73%
Expected Future Income Taxes	3,007	12,384	9,319
Increase (Decrease) in Future Income Taxes Resulting From:			
Non-deductible Crown Charges	12,543	12,904	7,293
Resource Allowance	(12,074)	(11,272)	(7,721)
Alberta Royalty Tax Credit	(636)	(544)	(656)
Attributed Canadian Royalty Income	(939)	(677)	(50)
Corporate Income Tax Rate Change	136	68	168
Non-deductible Depletion	25	28	–
Deferred Foreign Exchange Charges	350	42	–
Other	63	667	197
Future Income Taxes	2,475	13,600	8,550

The Corporation has the following deductions at December 31, 1998 available for future income tax purposes:

($ thousands)		Maximum Annual Rate of Claim
Canadian Exploration Expense	102,000	100%
Canadian Development Expense	78,000	30%
Canadian Oil and Gas Property Expense	132,000	10%
Undepreciated Capital Cost	111,000	6-30%
	423,000	

Approximately $20.0 million of the Company's tax pools are successored due to the change of control resulting from corporate acquisitions and may only be claimed against future net production revenues from the acquired properties.

9. Commitments and Contingencies

Commitments

Commitments are entered into in the normal course of business.

Uncertainty Due to the Year 2000 Issue

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. While the Company has a plan to address the Year 2000 Issue, it is not possible to be certain that all aspects of the issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

10. US GAAP and US Dollar Summary Information

The Company's financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Company's financial statements, differ from US GAAP as follows:

The application of US GAAP would have the following effects on net earnings and comprehensive income as reported:

(CDN$ thousands for years ended December 31)	1998	1997	1996
Net Earnings - Canadian GAAP	2,737	13,031	11,518
Deferred Foreign Exchange Losses (1)	(7,017)	(2,706)	–
Depletion and Depreciation (2)	5,056	5,853	6,533
Future Income Taxes (2)	973	196	(2,619)
Foreign Exchange Forward Contracts (3)	174	(4,437)	(442)
	(814)	(1,094)	3,472
Net Earnings and Comprehensive Income - US GAAP	1,923	11,937	14,990
Net Earnings per Share (Basic and Fully Diluted) in Accordance with US GAAP (as a result of the above adjustments)	0.02	0.11	0.14

The application of US GAAP would have the following effects on the balance sheets as reported:

(CDN$ thousands at December 31)	1998		1997	
	Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Petroleum Property and Equipment	584,512	538,985	487,137	436,126
Deferred Foreign Exchange Losses (1)	7,017	–	2,706	–
Future Income Taxes (2)	61,034	44,369	58,559	35,296
Retained Earnings (Deficit) (1,3)	27,456	(8,249)	24,719	(10,172)

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(1) In accordance with US GAAP, unrealized gains or losses arising on translation of long term liabilities repayable in foreign funds would be included in earnings in the period in which they arise. See Note 1 for Canadian GAAP treatment.

(2) In accordance with US GAAP, the discounted future net cash flows from proven reserves, discounted at 10 percent over the remaining productive life, plus the lower of cost or estimated fair market value of unproved properties, net of future taxes, must exceed the net book value to such properties, net of future taxes and estimated site restoration, or a write down is required. Under Canadian GAAP, the ceiling test calculation is computed on an undiscounted basis. At December 31, 1998, 1997 and 1996, no ceiling test writedowns under either Canadian GAAP and US GAAP were required. Under US GAAP, the liability method of accounting for income taxes and the ceiling test calculation in years prior to 1995 resulted in differences in the carrying values of petroleum property and equipment, future income taxes liability, depletion and depreciation, and future income taxes expense.

(3) In accordance with US GAAP, foreign exchange forward contracts associated with anticipated future transactions are recognized in the financial statements at fair value, with any resulting gain or loss immediately reflected in income. Under Canadian GAAP, these contracts are accounted for as a hedge of the anticipated future transactions. Accordingly, gains and losses arising on the contracts are deferred and recognized in income in the period in which the underlying transactions are recognized.

In June 1998, the Financial Accounting Standards Board issued Statement No. 133, Accounting for Derivative Instruments and Hedging Activities ("The Statement"), which is required to be adopted in years beginning after June 15, 1999. The Statement permits early adoption as of the beginning of any fiscal quarter after its issuance. The Company expects to adopt the new Statement effective January 1, 2000. The Statement will require the Company to recognize all derivatives on the balance sheet at fair value. Derivatives that are not hedges must be adjusted to fair value through income. If the derivative is a hedge, depending on the nature of the hedge, changes in the fair value of derivatives will either

be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value will be immediately recognized in earnings.

The Company has not yet determined what the effect of The Statement will be on the earnings and financial position of the Company.

The following information is based on US GAAP and translated from Canadian into US dollars at the average exchange rates for each of the years presented.

(US$ thousands except per share amounts)	Year ended December 31 1998	1997	1996
Petroleum and Natural Gas Sales	118,230	122,849	94,251
Net Earnings and Comprehensive Income	1,288	8,595	10,943
Per Share - Basic	0.02	0.08	0.10
Per Share - Fully Diluted	0.02	0.08	0.10
Cash Flow from Operations	49,677	60,553	48,322
Per Share - Basic	0.47	0.58	0.47
Per Share - Fully Diluted	0.46	0.57	0.46
Average Exchange Rate (CDN$)	0.67	0.72	0.73

Stock Option Plan

No amount of compensation expense has been recognized in the financial statements for stock options granted to employees and directors. The following table provides pro forma measures of net earnings and net earnings per share in accordance with US GAAP had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date in accordance with SFAS No. 123.

	1998		1997		1996	
	As reported	Pro Forma	As reported	Pro Forma	As reported	Pro Forma
Net Earnings ($ thousands)	2,737	809	13,031	11,720	11,518	10,768
Net Earnings per share	0.03	0.01	0.12	0.11	0.11	0.10

The pro forma amounts are not indicative of future results as options generally vest over three years (and are reflected as compensation expense in the above table over this period) and SFAS No. 123 does not apply to options granted prior to 1995. Additional awards in future years are anticipated.

Stock options granted in 1998 had an estimated weighted average fair value of $1.85 per option (1997 - $1.63 per option, 1996 - $1.39 per option). All options issued by the Company permit the holder to purchase one common share at the stated exercise price.

The estimated fair value of stock options issued was determined using the Black-Scholes model using the following weighted average assumptions:

	1998	1997	1996
Risk free interest rate (%)	5.13	5.46	6.48
Estimated hold period prior to exercise (years)	4	4	4
Volatility in the price of the Company's common shares (%)	34.6	34.8	37.8

1998 Selected Quarterly Information

Financial Highlights

($ thousands except per share amounts)	Three Months Ended 1998 March 31	June 30	Sept. 30	Dec. 31	Annual 1998
Income Statement					
Petroleum and Natural Gas Sales	42,753	39,384	43,249	51,077	**176,463**
Cash Flow from Operations	18,731	16,021	17,414	21,978	**74,144**
Per Share - Basic	0.18	0.15	0.17	0.20	**0.70**
Per Share - Fully Diluted	0.17	0.15	0.15	0.20	**0.67**
Net Earnings	1,464	(275)	(350)	1,898	**2,737**
Per Share - Basic	0.01	0.00	0.00	0.02	**0.03**
Per Share - Fully Diluted	0.01	0.00	0.00	0.02	**0.03**
Balance Sheet					
Capital Spending					
Land and Lease	1,956	2,683	2,573	2,553	**9,765**
Seismic	1,539	396	1,940	353	**4,228**
Eastern Canada	–	2,503	2,596	1,976	**7,075**
Drilling and Completions	25,421	17,403	17,384	15,733	**75,941**
Facilities	13,336	10,339	12,300	13,098	**49,073**
Property Dispositions	(1,999)	(656)	(1,052)	(45,362)	**(49,069)**
Property Acquisitions	12,866	4,098	3,437	44,053	**64,454**
Corporate Assets	688	476	419	456	**2,039**
	53,807	37,242	39,597	32,860	**163,506**
Total Debt					
Bank Debt	93,185	118,276	138,638	146,736	
Senior Notes Payable	70,830	73,580	76,295	76,525	
Working Capital Deficiency	23,119	17,872	19,271	20,968	
	187,134	209,728	234,204	244,229	
Total Shareholders' Equity	271,960	273,135	273,543	276,863	

	March 31	June 30	Sept. 30	Dec. 31
Share Information (thousands)				
Shares Outstanding at End of Period				
- Basic	105,198	105,631	105,854	106,235
- Fully Diluted	110,694	110,654	112,985	113,161
Weighted Average Shares Outstanding for the Period				
- Basic	104,936	105,392	105,711	106,082
- Fully Diluted	110,623	110,677	112,296	113,105
Volume Traded During Quarter - TSE	5,057	8,030	5,159	8,227
Volume Traded During Quarter - NYSE	72	174	39	206
Controlled by Management and Directors (%)	40	39	39	37
Public Float (%)	60	61	61	63
Share Price ($) - TSE				
- High	5.60	6.15	5.95	6.25
- Low	4.01	5.05	4.25	4.50
- Close	5.20	5.50	5.80	5.70
Equity Market Capitalization At Closing Price ($)	547,030	580,971	613,953	605,540

1998 Selected Quarterly Information

Operational Highlights

($ thousands except per share amounts)	Three Months Ended 1998 March 31	June 30	Sept. 30	Dec. 31	Annual 1998
Production					
Natural Gas (mcf/d)	140,734	135,411	145,683	150,429	143,098
Crude Oil (bbls/d)	8,810	9,143	9,272	10,016	9,313
Natural Gas Liquids (bbls/d)	2,737	2,633	3,453	3,447	3,071
Total (BOE/d)	25,620	25,317	27,293	28,506	26,694
Pricing					
Natural Gas ($/mcf)	1.94	1.83	1.92	2.32	2.01
Crude Oil ($/bbl)	17.96	15.96	15.63	16.26	16.43
Natural Gas Liquids ($/bbl)	16.41	14.77	13.20	12.28	13.98
Royalties, net of ARTC ($/BOE)	3.61	2.78	2.37	3.28	3.00
Operating Costs ($/BOE)	4.33	4.37	4.39	4.13	4.30
Operating Netbacks ($/BOE)	10.37	9.56	9.47	10.95	10.10
General and Administrative ($/BOE)	1.11	1.13	1.01	0.94	1.04
Depletion and Depreciation ($/BOE)	7.00	7.00	6.97	7.03	7.00
Drilling Results (Gross Wells)					
Natural Gas	35	11	10	6	62
Crude Oil	17	14	6	8	45
Dry	10	4	12	5	31
Total Drilled	62	29	28	19	138
Drilling Results (Net Wells)					
Natural Gas	16.7	5.1	5.9	4.3	32.0
Crude Oil	10.2	6.8	3.3	5.8	26.1
Dry	7.9	3.0	10.2	3.1	24.2
Total Drilled	34.8	14.9	19.4	13.2	82.3
Success Rate (%)	77	80	47	77	71

1997 Selected Quarterly Information

Financial Highlights

($ thousands except per share amounts)	Three Months Ended 1997 March 31	June 30	Sept. 30	Dec. 31	Annual 1997
Income Statement					
Petroleum and Natural Gas Sales	47,264	36,829	38,163	48,368	**170,624**
Cash Flow from Operations	25,212	17,814	17,378	23,697	**84,101**
Per Share - Basic	0.24	0.17	0.17	0.23	**0.81**
Per Share - Fully Diluted	0.23	0.16	0.16	0.22	**0.77**
Net Earnings	6,112	1,989	1,369	3,561	**13,031**
Per Share - Basic	0.06	0.02	0.01	0.03	**0.12**
Per Share - Fully Diluted	0.06	0.02	0.01	0.03	**0.12**
Balance Sheet					
Capital Spending					
Land and Lease	6,505	3,998	6,423	1,087	**18,013**
Seismic	5,779	1,321	627	1,153	**8,880**
Drilling and Completions	20,305	4,859	22,037	25,795	**72,996**
Facilities	12,597	8,229	8,422	10,627	**39,875**
Property Dispositions	(5,413)	(6,861)	(14,336)	(13,551)	**(40,161)**
Property Acquisitions	47,087	5,415	3,794	770	**57,066**
Corporate Assets	544	768	256	(83)	**1,485**
	87,404	17,729	27,223	25,798	**158,154**
Total Debt					
Bank Debt	117,187	130,388	64,238	71,959	
Senior Notes Payable	–	–	69,100	71,455	
Working Capital Deficiency	23,760	9,493	15,537	10,409	
	140,947	139,881	148,875	153,823	
Total Shareholders' Equity	260,588	263,138	265,489	269,228	

	March 31	June 30	Sept. 30	Dec. 31
Share Information (thousands)				
Shares Outstanding at End of Period				
- Basic	104,219	104,395	104,721	104,784
- Fully Diluted	109,940	110,267	110,450	110,577
Weighted Average Shares Outstanding for the Period				
- Basic	104,102	104,318	104,498	104,757
- Fully Diluted	109,883	110,275	110,499	110,565
Volume Traded During Quarter - TSE	8,576	4,562	6,519	8,588
Volume Traded During Quarter - NYSE	–	31	363	406
Controlled by Management and Directors (%)	40	40	40	41
Public Float (%)	60	60	60	59
Share Price ($) - TSE				
- High	4.40	4.95	5.75	5.75
- Low	3.90	3.95	4.00	4.40
- Close	4.00	4.75	5.35	4.70
Equity Market Capitalization At Closing Price ($)	416,876	495,876	560,257	492,485

1997 Selected Quarterly Information

Operational Highlights

($ thousands except per share amounts)	Three Months Ended 1997 March 31	June 30	Sept. 30	Dec. 31	Annual 1997
Production					
Natural Gas (mcf/d)	130,606	123,226	128,910	137,981	130,197
Crude Oil (bbls/d)	6,217	6,156	7,145	8,180	6,931
Natural Gas Liquids (bbls/d)	2,188	2,659	2,226	2,877	2,485
Total (BOE/d)	21,466	21,138	22,262	24,855	22,436
Pricing					
Natural Gas ($/mcf)	2.22	1.64	1.60	2.02	1.88
Crude Oil ($/bbl)	27.68	23.98	22.97	23.14	24.25
Natural Gas Liquids ($/bbl)	27.03	19.47	19.99	20.12	21.45
Royalties, net of ARTC ($/BOE)	4.58	3.46	3.30	4.07	3.86
Operating Costs ($/BOE)	4.37	4.20	4.32	4.23	4.28
Operating Netbacks ($/BOE)	14.95	11.23	10.78	12.55	12.36
General and Administrative ($/BOE)	1.10	1.13	1.15	0.94	1.07
Depletion and Depreciation ($/BOE)	7.09	7.15	7.06	6.78	7.01
Drilling Results (Gross Wells)					
Natural Gas	34	–	11	21	66
Crude Oil	11	9	14	41	75
Dry	22	1	13	4	40
Total Drilled	67	10	38	66	181
Drilling Results (Net Wells)					
Natural Gas	20.0	–	8.6	11.3	39.9
Crude Oil	3.3	6.2	11.5	26.3	47.3
Dry	16.8	0.1	10.5	3.8	31.2
Total Drilled	40.1	6.3	30.6	41.4	118.4
Success Rate (%)	58	98	66	91	74

Historical Review

Year ended December 31 ($ thousands except per share data)	1998	1997	1996	1995	1994	1993	1992
Financial							
Petroleum and Natural Gas Sales	176,463	170,624	129,110	98,359	82,870	47,981	6,386
Cash Flow from Operations	74,144	84,101	66,195	44,910	41,483	24,719	3,247
Per Share - Basic	0.70	0.81	0.64	0.43	0.51	0.59	0.16
Per Share - Fully Diluted	0.67	0.77	0.62	0.42	0.50	0.51	0.12
Net Earnings (Loss)	2,737	13,031	11,518	(964)	4,480	4,757	880
Per Share - Basic	0.03	0.12	0.11	(0.01)	0.06	0.11	0.04
Per Share - Fully Diluted	0.03	0.12	0.11	(0.01)	0.06	0.10	0.03
Net Capital Expenditures	163,506	158,154	109,280	40,411	198,305	130,961	5,480
Total Assets	630,039	514,132	410,141	346,102	348,243	147,027	18,979
Working Capital Deficiency	(20,968)	(10,409)	(14,961)	(7,269)	(14,297)	(2,584)	(1,793)
Long Term Debt	223,261	143,414	64,046	28,126	25,678	5,560	5,792
Shareholders' Equity	276,863	269,228	253,736	241,702	250,448	121,084	8,950
Weighted Average Common Shares							
(Fully Diluted, thousands)	111,684	110,334	108,111	106,651	83,911	61,654	26,917
Operating							
Production							
Natural Gas (mcf/d)	143,098	130,197	105,713	102,201	76,303	49,744	8,360
Crude Oil and NGL (bbls/d)	12,384	9,416	7,232	6,708	4,680	2,605	208
Total (BOE/d)	26,694	22,436	17,803	16,928	12,310	7,579	1,044
Average Price							
Natural Gas ($/mcf)	2.01	1.88	1.62	1.30	1.84	1.75	1.61
Crude Oil and NGL ($/bbl)	15.82	23.52	25.18	20.19	18.36	17.02	18.95
Proven plus Probable Reserves							
Natural Gas (bcf)	681.5	604.7	520.1	462.2	477.5	256.3	52.3
Crude Oil and NGL (mbbls)	47,837	40,912	28,680	26,053	23,077	12,497	1,521
Present Value ($ thousands discounted							
at 12% before income taxes)	729,000	671,000	519,000	414,000	445,000	269,000	48,000
Undeveloped Land							
Gross Acres (thousands)	3,397	1,132	1,132	1,138	1,463	1,133	60
Net Acres (thousands)	859	719	601	501	639	423	20

Shareholder Information

Registrar and Transfer Agent
CIBC Mellon Trust Company
600, 333 - 7th Avenue S.W.
Calgary, Alberta
T2P 2Z1
Phone: (403) 232-2400
Fax: (403) 264-2100
E-mail: inquires@cibcmellon.ca
Web Site: www.cibcmellon.ca
Answerline: 1-800-387-0825

Chase Mellon Shareholder Services
New York, New York

Stock Exchange Listing
The Toronto Stock Exchange
Symbol: ENL
New York Stock Exchange
Symbol: ECA

Shareholder Contacts

Shareholders are welcome to contact the Company for information or questions concerning their shares. For general information about the Company, contact Mrs. Karen Ruzicki or Mr. Steven Allaire Vice President Finance at (403) 750-3300.

For information on such matters as share transfers and change of address inquiries should be directed to the Transfer Agent. The address and telephone number of the transfer agent are listed above.

Annual Information Form

Copies of the Annual Information Form are available to shareholders upon request.

French Material

Copies of the Information Circular, Notice of the Annual General Meeting, Proxy, Management Discussion and Analysis and Financial Statements are available in french.

Dividend Policy

The Company does not pay dividends as cash flow is utilized to support current operations, exploration and development programs and to fund acquisitions of oil and gas properties.

Annual Meeting

The Annual General Meeting of Shareholders will be held on:

Tuesday, May 4, 1999
at 3:00 p.m. in the McMurray Room
Calgary Petroleum Club
Calgary, Canada

Estimated Release Dates of Quarterly Results

First Quarter	April 28, 1999
Second Quarter	July 28, 1999
Third Quarter	October 28, 1999

Corporate Governance

A system of corporate governance for the Corporation has been established to provide the Board of Directors, management and shareholders of the Corporation with effective governance. A more detailed discussion of corporate governance is available in the Information Circular for the Annual and Special General Meeting of Shareholders.

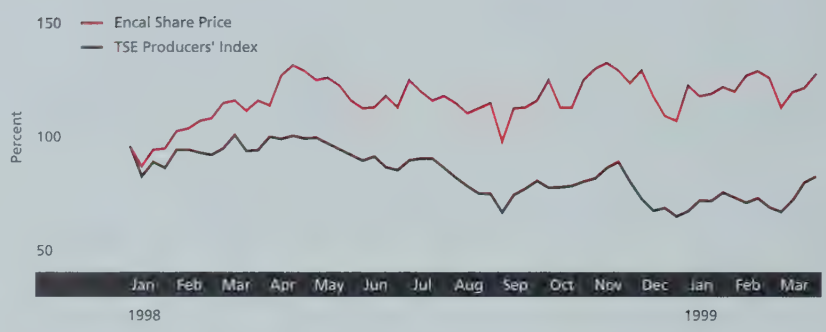
Internet

Encal is on the internet. Look for our home page for access to recent press releases, quarterly reports and annual report information at Web Site: http://www.encal.com

Share Information

TSE Share Performance

Encal Relative Performance
Encal TSE Share Price vs. TSE Producers' Index



Share Information

Common Shares

Outstanding December 31, 1998	
Basic	106,235,000
Fully Diluted	113,161,000
Weighted Average December 31, 1998	
Basic	105,534,000
Fully Diluted	111,684,000
Closing Price of Shares - December 31, 1998	$5.70
Market Capitalization (using December 31, 1998 closing price)	$605,540,000
Controlled by management and the Board of Directors	37%
Public Float	63%
Major Shareholders TMI - FW Inc.	30,074,000

Share Trading Information

Volume of Shares Traded during 1998

TSE	25,947,000
NYSE	491,000

Abbreviations

AECO	- Alberta Energy Company (reference price for natural gas)
API	- American Petroleum Institute
ARTC	- Alberta Royalty Tax Credit
Bbls	- barrels
Bbls/d	- barrels per day
Bcf	- billions of cubic feet
BOE	- barrels of oil equivalent
Bopd	- barrels of oil per day
Btu	- British Thermal Unit
Condensate	- A mixture of pentane and heavier hydrocarbon that is gaseous in its reservoir state, but which condenses to a liquid at atmospheric pressure and temperature
Mbbls	- thousands of barrels
Mboe	- thousands of barrels of oil equivalent
Mcf	- thousands of cubic feet
Mcf/d	- thousands of cubic feet per day
Mmcf	- millions of cubic feet
Mmcf/d	- millions of cubic feet per day
NIT	- Nova Inventory Transfer
NPV	- Net Present Value
NYMEX	- New York Mercantile Exchange
US	- United States
WTI	- West Texas Intermediate, oil price reference set at Cushing, Oklahoma

Metric Conversion Table

The Canadian Petroleum industry uses the International System of Units for measuring and reporting. The following table notes conversion factors relevant to this report.

To convert from	To	Multiply by
Thousand cubic feet	Thousand cubic metres	0.028169
Barrels	Cubic Metres	0.159000
Feet	Metres	0.305000
Miles	Kilometres	1.609000
Acres	Hectares	0.405000

Corporate Information

Directors

Thomas M. Taylor*
Chairman
Encal Energy Ltd.
Taylor & Co.
Fort Worth, Texas

David D. Johnson
President and CEO
Encal Energy Ltd.
Calgary, Alberta

Robert G. Jennings†
President
Jennings Capital Inc.
Calgary, Alberta

Harold P. Milavsky*†
Chairman
Quantico Capital Corp.
Calgary, Alberta

Byron J. Seaman†
Private Investor
Calgary, Alberta

Daryl K. Seaman*
President
Dox Investments Ltd.
Calgary, Alberta

Officers

David D. Johnson
President and CEO

Steven A. Allaire
Vice President, Finance and CFO

Terrence R. Barrows
Vice President, Production

Peter A. Carwardine
Vice President, Land and Corporate Development

Michael R. Culbert
Vice President, Marketing

James D. Reimer
Vice President, Exploration

Arthur A. MacNichol
Controller

Gordon M. Adams
Secretary

**Members of Compensation Committee*
† Members of Audit Committee

Management

Robert S. Attwood
Manager, Information Technology

Geoff W. Beatson
Manager, Engineering

Greg W. Chury
Manager, West Central Team

Glenn A. Downey
Manager, Exploration

Kathy L. Howell
Manager, Financial Reporting

Gerri M. Murphy
Manager, Contracts and Land Administration

Greg D. Neufeld
Manager, Operations

Robert R. Padget
Manager, BC Team

Ronald A. Parent
Manager, Human Resources

David K. Saul
Manager, Operational Accounting

David M. Sterna
Manager, Risk Management and Liquids Marketing

Brian Vermeulen
Manager, Surface Land
Aboriginal and Community Relations

Gordon B. Vogt
Manager, Asset Enhancement Team

Tim J. Wollen
Manager, Production

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T2P 3Y7

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